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EXTERNAL PITTING AND CREVICE CORROSION OF 316L STAINLESS STEEL INSTRUMENT TUBING IN MARINE ENVIRONMENTS AND PROPOSED SOLUTION

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ABSTRACT

Severe corrosion of the small bore 316L stainless steel instrument tubing was observed during construction and pre-commissioning activities, less than a year after the FPSO was moored in place offshore in the Gulf of Guinea. A total length of about 8km (5 miles) of 316 stainless steel instrument tubing had to be replaced prior to commissioning and start up with a replacement cost of over $5Million.

A thorough failure analysis of the failed tubing was carried out and it was concluded that the failure was as a result of pitting and crevice corrosion, but no stress corrosion cracking (SCC). The Materials and Corrosion Team evaluated various replacement options such as Polyvinyl chloride (PVC) or Thermoplastic polyurethane (TPU) sheathed AISI 316L, high-pressure steel reinforced polymer hoses and various corrosion resistant alloys. Using a life cycle cost analysis and proper consideration of lead-time requirement for the material as the basis for selection, the fire retardant and UV resistant thermoplastic polyurethane jacketed 316L stainless instrument tubing was selected and installed. Currently there is almost two years of good track record.

Keywords: 316L stainless steel, pitting, crevice, instrument tubing

INTRODUCTION

External pitting and crevice corrosion of AISI 316L tubing is quite common in the oilfield and well known to be strongly influenced by the presence of chlorides and the temperature. However, there are clear indications that problems with AISI 316L have worsened over the past decade and it has been suggested repeatedly that this is related to the fact that tubing manufacturers are now capable of minimizing the alloy content of the materials whilst still adhering to the ASTM specifications of chemical composition. In particular a minimal Molybdenum content very close to the lower limit of 2.0% has been observed and it is well established that Mo plays a key role in providing resistance to localized corrosion. TABLE 1 shows the required concentrations of each element according to the AISI specification for 316L and chemical composition obtained from four different tubing analyses.

TABLE 1: CHEMICAL COMPOSITION OF AISI 316L

AISI 316L specification		C	Mn	Si	P	S	Ni	Cr	**Mo**
	max	0.030	2.00	1.00	0.045	0.030	14.0	18.0	**3.00**
	min						10.0	16.0	**2.00**
Analyzed tubing	1	0.027	1.70	0.29	0.021	0.010	11.20	17.20	**2.06**
	2	0.024	1.48	0.48	0.030	0.004	11.26	16.62	**2.08**
	3	0.020	1.78	0.37	0.021	0.010	11.39	17.05	**2.05**
	4	0.010	1.67	0.47	0.029	0.008	11.10	17.01	**2.00**

In one of our projects in the Gulf of Guinea, less than a year after the FPSO was moored in place offshore, severe corrosion of the small bore AISI 316L stainless steel instrument tubing was observed in several locations in the topside facilities. Of particular attention in this paper are two failures, the first of which was an isolated local tubing failure inside a tubing termination panel, adjacent to a Gas Lift Riser on the starboard side while the second failure occurred during a routine integrity checks of the hydraulic tubing used to operate the gas lift riser valves at working pressure (3000psi/200bar). Tubing leaks were encountered in six different locations, all within the same layer and vicinity of an horizontal supporting rack. Fortunately both incidents were properly controlled and contained without any injury.

Pitting under plastic retainer blocks, rubber isolators and general pitting corrosion of AISI 316L stainless steel tubing is also heard of from other oil and gas production companies. It is well known that pitting and crevice corrosion of austenitic stainless steels are strongly influenced by the presence of chlorides and temperature, so it is no surprise users report good experience with AISI 316L onshore and in cooler climates. There are strong indications that problems with AISI 316L especially when subjected to marine conditions have worsened over the past decade and it has been suggested repeatedly that this is related to the fact that tubing manufacturers are now capable of minimizing the alloy content of the materials whilst still adhering to the ASTM specification. In particular a minimal Molybdenum content very close to the lower limit of 2% has been observed and it is well established that Mo plays a key role in providing resistance to localized corrosion. Another factor that may play a key role is the increased use of iron and copper contaminated slag versus silica sand in blasting operations associated with painting of carbon steel elsewhere on the FPSO, increasing the likelihood of metal over blast tubing contamination. This is particularly relevant, as integrated work practices have become common practice in major projects construction. This implies that certain equipment may be installed and painted after the installation of instrument tubing elsewhere on the facility, which increases the likelihood of instrument line iron contamination.

As a result of these failures, a total length of about 8 km (5 miles) of AISI 316L stainless steel instrument tubing had to be replaced prior to commissioning and start up with a replacement cost of over $5Million using alternative materials. There is however, no general agreement about the most optimal alternative choice since the optimal choice is expected to depend on the exact service conditions, including temperature, humidity, pollution, contamination and piping designs. Hence it is unlikely that a "one size fits all" recommendation would be appropriate for all cases.

The objective of this paper is to present the available evidence regarding the AISI 316L stainless steel tubing corrosion, assess the risks associated with the corrosion problems and propose an engineering solution that Shell has adopted, stating the factors and options considered before the final selection was made.

FAILURE ANALYSIS

The first failure was topside stainless steel tubing associated with the Subsea Umbilical system, i.e. tubing between the Umbilical Termination Panels (UTP) and the so-called Medusa heads. Figure 1 shows the schematics of the tubing indicating four different failure locations. All the tubes were made of longitudinally welded AISI 316L with compression type connector except for the umbilical tubes that go Subsea that were made of Super Duplex Stainless Steel (SDSS) and are not addressed in this paper. The tubing contained hydraulic fluid and the four failures occurred within 6 months intervals, with the first failure just barely five months after the FPSO was moored in place.

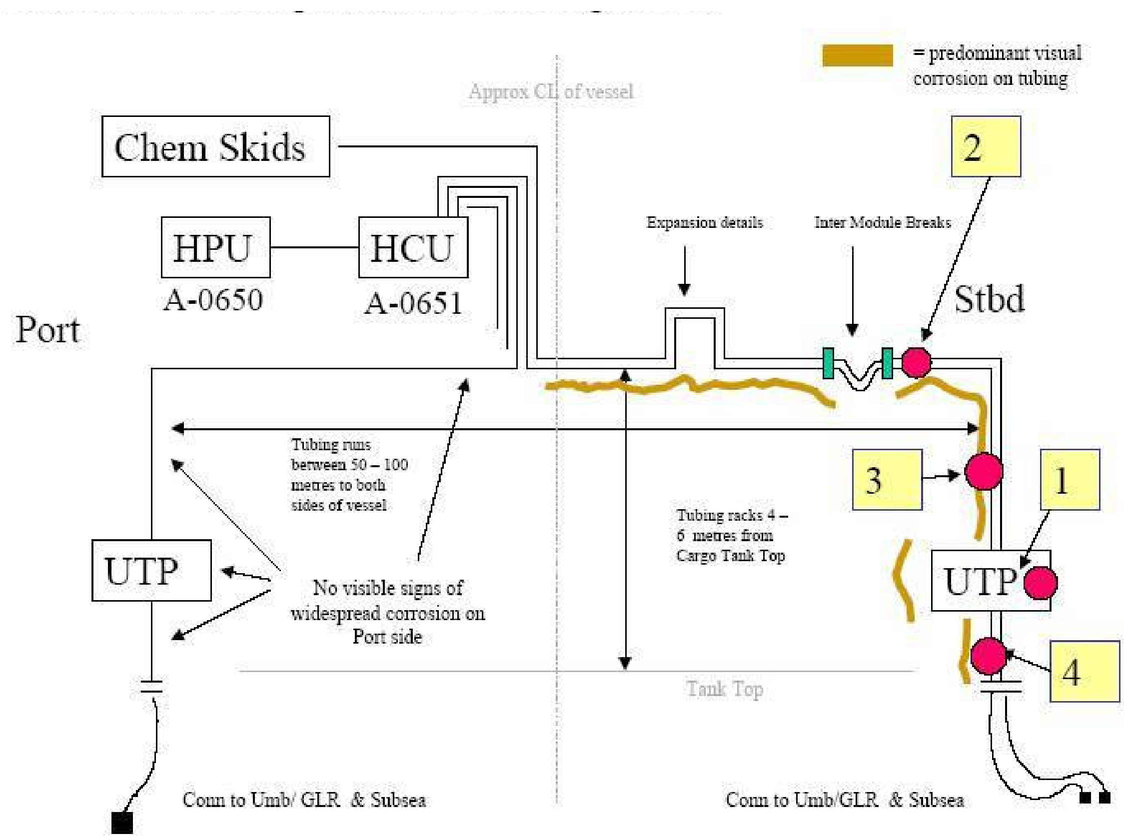

Figure 1: Subsea system tubing between the Umbilical Termination Panels (UTP) and the Medusa heads

The first incident was a pinhole leak during a pressure test within the UTP. The failed tube was analysed and the material confirmed to be AISI 316L with Molybdenum content of 2.08%. Figure 2 shows the pinhole leak while Figure 3 is the cross section of the tube showing the pit morphology, which is typical for stainless steel pitting such as caused by chlorides. Although there were many signs of general external corrosion, it was thought that most of these tubes were superficially attacked and the deeper attack that led to a failure was an isolated event caused by chloride pitting.

Figure 2 Pressure test leak within UTP

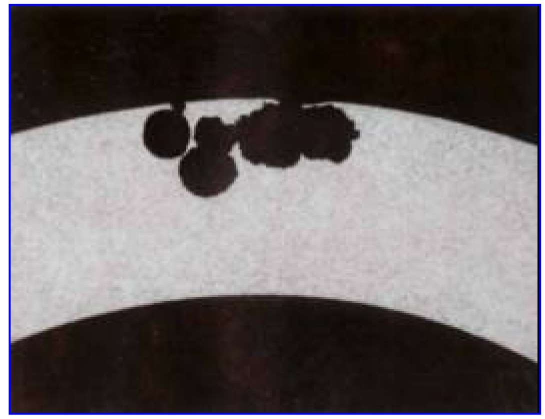

Figure 3: Cross-section of tube with pit

Within a very short time, corrosion propagated quite rapidly, it was however interesting to note that there were significant differences in the degree of attack between various locations. Corrosion was rampant on the starboard side of the vessel and much less on the port side.Figure 4 shows a tubing rack on the starboard side and location of failure site 3 identified in Figure 1. As a result of the mooring orientation, the starboard side is directed toward the prevailing wind, hence is more likely to be exposed to salt spray. The humidity is extremely high in the Gulf of Guinea hence most of the vessels and equipment are continuously moist, in addition heavy rain showers are common in the region. Although rain adds to the wetting of some surfaces, it also washes off some of the salt deposits. Apparently the net effect is favourable on the port side and not on the starboard side.

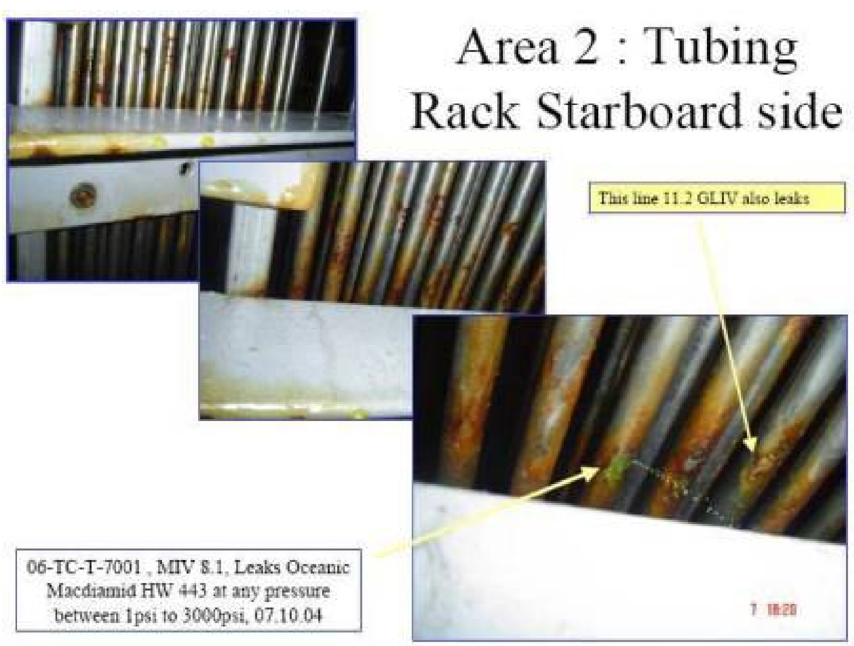

Figure 4:Tubing Rack on the Starboard side

It should be noted that the tubing shown in Figure 5 and Figure 6 are not directly exposed to rain water because they are located underneath a solid deck. In this case, corrosion is more prominent at the tube and union connector interface and also at the bends. A repeat failure analysis on other leak sites concluded that the failure mechanism was the same as the initial failure. Again the Mo content was minimal (2.05%). The failure analysis concluded that the failure mechanism was pitting and crevice corrosion. No crack was observed in any of the failures. This is consistent with the collective experience of other oil companies interacted with. The only stress corrosion cracking (SCC) failure that has been experienced on small-bore tubing was chloride SCC of an over-stressed bend in a Middle Eastern location.

Different types of clamps were used to secure the stainless steel tubing in place; it is however remarkable that tubing fastened with certain fasteners suffered crevice corrosion whereas those fastened with another brand were still in good condition.

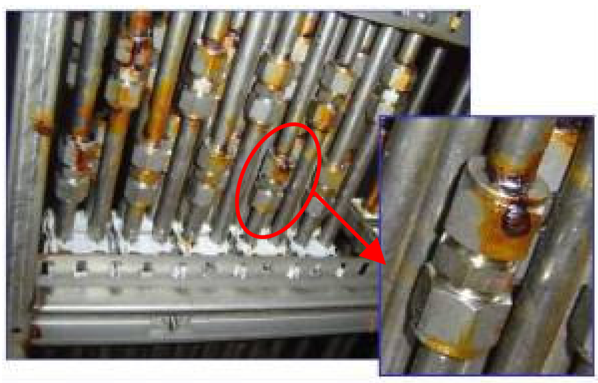

Figure 5: Corrosion of tubing and couplings

Figure 6: Deep pits on bends

Another area where multiple corrosion sites were observed was very close to the machine shop where grinding and blasting activities were performed during the construction and integration phase. Contamination with iron particles associated with grinding and blasting activities possibly initiated the corrosion problem in this case.

Based on the corrosion failures experienced on this project that were described above and those experienced in other projects, it was concluded that AISI 316L stainless steel tubing is susceptible to degradation under normal operating conditions in a marine environment.

Using a risk assessment matrix, the criticality will depend on the consequence of failure in terms of economics, Health/Safety and Environment. The fact that AISI 316L is susceptible under normal operating conditions in a marine environment and that the consequence could be grievous depending on the exposure, AISI 316L is deemed not acceptable for this service in marine environment.

The corrective action taken was to replace all the AISI 316L tubing on the starboard side immediately with an alternative material and a recommendation to replace those on the port side within twelve months considering the degree of crevice corrosion at the clamps.

MATERIALS SELECTION OPTIONS FOR REPLACEMENT

Using a life cycle cost analysis and proper consideration of lead-time requirement as the basis for materials selection, the various options that were considered is as given in TABLE 2, which lists the pros and cons of the various factors taken into consideration and the main limitations of each option.

TABLE 2: EVALUATION OF DIFFERENT MATERIALS OPTION

Option	UNS code	Resistance to Pitting Corrosion	Under deposit / galvanic	Experience	Ease of Installation	Resistance to Transportation Damage	Resistance to Service Damage	Life expectancy	Main Limitations
AISI 316L	S31603	-	-	-	+	+	+	-	PREN value
AISI 316L, min 2.5%Mo	S31603	-	-	-	+	+	+	-	PREN value
AISI 317L	S31703	-	-	+/-	+	+	+	+/-	PREN value
Alloy 20	N08020	+/-	-	+/-	+	+	+	+/-	PREN value
Alloy 825	N08825	+/-	-	+/-	+	+	+	+/-	PREN value
22Cr Duplex	S32205	-	-	-	+/-	+	+	+	PREN value
25Cr Duplex	S22550, S22560, S32750	+	+/-	+	+/-	+	+	+	PREN value has to be >41.5
254SMO	S31254	+/-	+	+/-	+	+	+	+	
Al 6XN	N08367	+/-	+	+/-	+	+	+	+	
Alloy 625	N06625	+	+	+	+	+	+	+	
Alloy C276	N10276	+	+	+	+	+	+	+	
Tungum	C69100 (Cu 81-86, Zn)	+	+	+	+	+	+/-	+	Special tools may be required
Monel 400	N04400 (Ni 63-70, Cu)	+		+	+	+	+/-	+	Special tools may be required
Titanium		+	+	+	+	+	+	+	
PVC sheathed 316L/317L		+	+	+	+/-	+/-	+	+	Tools, fitting wrap, damage resistance
Tape wrapped 316L		+/-	+	+	-	NA	+/-	+	Difficult application, labor intensive
Painted 316L		+/-	-	+/-	+/-	-	-	+/-	Sensitive to damage
Ensis Coated 316L		+/-	-	+/-	+/-	NA	-	-	Temporary solution only

TABLE 3 gives the minimum and maximum Pitting Resistance Equivalent Numbers (PREN) based on specified composition of the materials considered. This indicator has been widely advocated by stainless steel manufacturers and has gradually been accepted by users over the past decades. A common cut-off PREN for seawater injection systems and umbilical tubes are 40 and 42.5 respectively, which are thought to be good reference points for these applications, considering the fact that regular salt water washing (e.g. from deluge systems and other washes) will remove any salt build-up that occurs. Since the PREN values are determined using exposure test in ferric chloride ($FeCl_3$), a high value like 42.5 is also considered sufficient to offer good resistance against corrosion caused by surface contamination with iron particles.

TABLE 3: PITTING RESISTANCE EQUIVALENT NUMBERS OF VARIOUS OPTIONS CONSIDERED

	Composition Ranges								PREN	
	Cr		Mo		W		N		Minimum	Maximum
AISI 316	16	18	2	3					22.6	27.9
AISI 316L	16	18	2	3					22.6	27.9
AISI 316L, >2.5%Mo	16	18	2.5	3					24.3	27.9
AISI 317	18	20	3	4				0.1	27.9	34.8
AISI 317L	18	20	3	4				0.1	27.9	34.8
Alloy 20	19	21	2	3					25.6	30.9
Alloy 825	19.5	23.5	2.5	3.5					27.8	35.1
22Cr Duplex	22	23	3	3.5			0.14	0.2	34.1	37.8
25 Cr Duplex	24	26	3	5			0.24	0.32	37.7	47.6
Al 6XN	20	22	6	7			0.18	0.25	42.7	49.1
254SMO	19.5	20.5	6	6.5			0.18	0.22	42.2	45.5
Alloy 625	20	23	8	10					46.4	56.0
Alloy C276	14.5	16.5	15	17	3	4.5			69.0	80.0

(PREN = % Cr + 3.3 %Mo + 1.65 %W + 16 %N)

Figure 7 gives a comparison of life cycle cost (prices for initial installation and future rework) in USD/ft based on 20-year life of ½" diameter instrument tubing taking into account high strength and wall thickness reduction for pressure calculations.

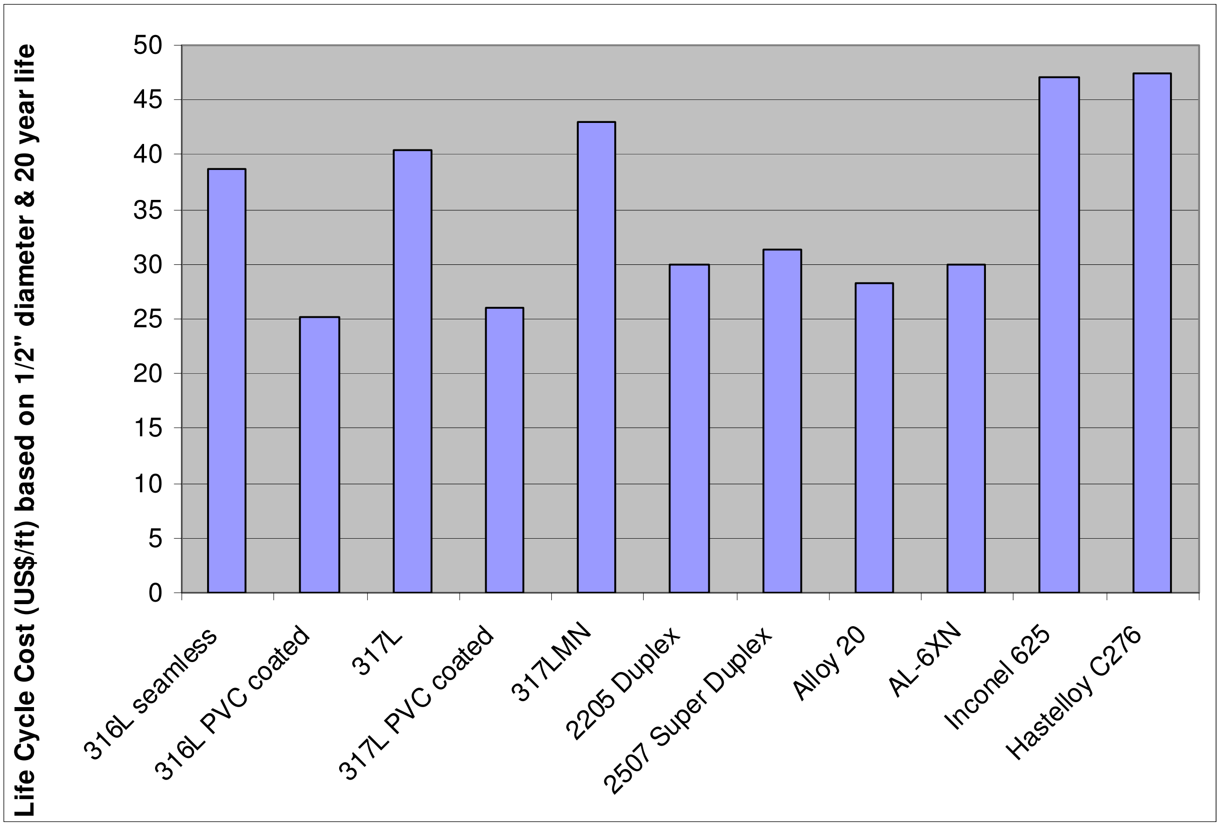

Figure 7: Lifetime Capital Cost Comparison for Instrument Tubing

Description of the various options considered

1. AISI 316L with a guaranteed Mo content of 2.5% and AISI 317L, which contains at least 3% Mo are more resistant than the standard AISI 316L with minimum Mo content of 2.0%. There are some reports of successful use of these options, but also some failures. Where modifications to common construction practice include the use of AISI 317, debris wash down during construction, avoidance of iron contaminated and drilling mud over spray, the experience was generally favorable. Given current experience coupled with the fact that the PREN values are well below 40 (which implies that pitting and crevice corrosion cannot be totally ruled out), the use of either AISI 316L or AISI 317L without an external sheath is not considered robust enough for this application. In spite of the reported problems with AISI 316L tubing, no fitting failures have been documented to date although some superficial staining may occur. This is thought to be in part due to the thickness, but probably also to the fact that these items are not rolled or cold drawn like tube material. Hence AISI 316 fittings can be considered for use with some other more resistant tubing materials provided galvanic corrosion does not become an issue.
2. Alloy 825 and Alloy 20 have better corrosion resistance than AISI 316L. The use of Alloy 825 instrument tubing with AISI 316 fittings was recommended in a Best Practice Guide issued by our company's downstream business in September 2004. The primary concern in the process industry has been stress corrosion cracking (which typically initiates at pits). There are reports that Alloy 825 is used quite extensively in the Middle East, (i.e. at higher ambient temperatures) as alternative to AISI 316L, which had had poor performance. Alloy 825 has performed better than 316, but there have also been some reports of failures. This is however, not surprising considering its low PREN of 27.8 (min). Given the

PREN values below 40 and the exposure conditions that the material would be subjected to, again pitting and crevice corrosion cannot be ruled out. If these materials are used, their integrity should at least be monitored by means of regular visual inspection. In view of limited access for inspection these alloys are not considered suitable for the service.

3. Figure 8 gives the Critical Chloride Pitting Temperature of some common alloys measured using ASTM G 150

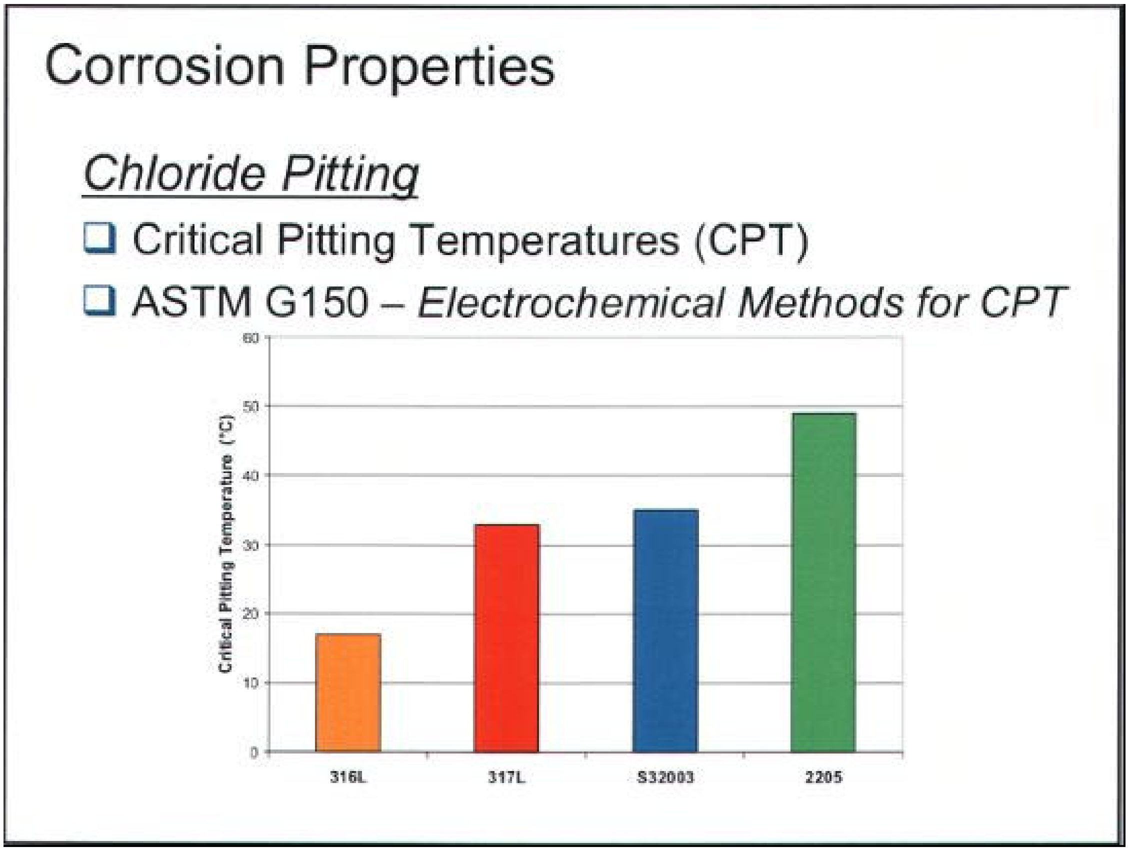

Figure 8: Critical Pitting Temperature[1]

The electrochemical method yields a CPT of 48^{o}C for Alloy 2205 as compared to 16^{o}C for AISI316L while Figure 9 gives the Critical Chloride Crevice Corrosion temperature of Alloy 2205 using ASTMG48B in a ferric chloride solution for 72 hours as 20^{o}C compared to –2^{o}C for AISI316L.

Although 22Cr duplex stainless steels seem to exhibit better resistance to pitting and crevice corrosion than AISI 316L nevertheless, they are known not to be suitable for aerated seawater service due to their extreme susceptibility to crevice corrosion. This material is not considered suitable for this application especially in the tropics where the temperature is usually above the critical crevice temperature almost all year round.

[1]Test data from ATI Allegheny Ludlum, November 2006

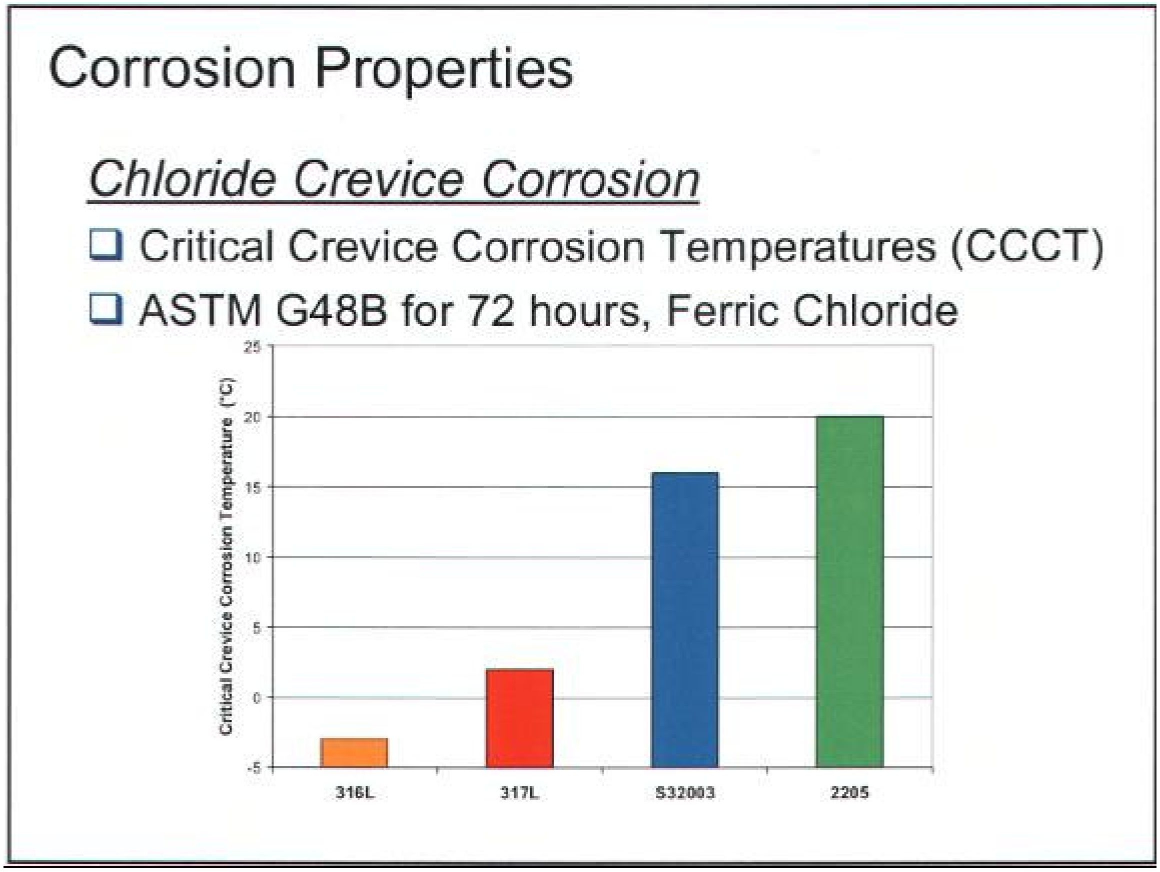

Figure 9: Critical Crevice Temperature[2]

4. 25Cr super duplex stainless steels have been applied successfully in umbilical and related systems in the Gulf of Mexico, provided that the composition is specified to ensure a PREN value in excess of 42.5. Since the material work hardens significantly, it is fairly difficult to install. This effect is partly offset by the required thickness reduction in view of its high strength. The hardness implies that the ferrules have to be specified to be at least equally hard to make leak free connections, which can affect their availability. This material is considered suitable for this application however considering the life cycle cost and availability it is not considered as the preferred option. It is our understanding that some of our competitors have used this material with a good track record for this application.
5. Stainless steel alloys with 6%Mo such as Al 6XN and 254SMO are even more resistant and were developed specifically for seawater service. The PREN values support the use of these materials. The latter material has been applied successfully in Malaysia to construct seawater lines. Crevice corrosion problems with these materials have been reported at elevated temperatures (80^{o}C) in Australia, but these materials are considered suitable for this application, as the temperatures of exposure will be lower. However, the initial procurement costs are relatively high hence they are not the preferred option for this application.
6. Tungum^{TM} and Monel 400 have been used with good success for some 30 years, e.g. on diving equipment. The former has been used in the Southern North Sea in all services including gas, hydraulics and air systems and no failure has been recorded due to corrosion as far as we are aware. In view of the somewhat lower strength the tubes would have to be rather thick, hence using this material would require special tools and changing out fasteners or clamp inserts. Also, it has been suggested that these materials are not suitable for HP natural gas service where mercury contamination could occur, although this issue may be theoretical since no failure has been reported to-date. On the other hand there is the possibility that no failure has occurred either because this material has not been used in service containing mercury

[2] Test data from ATI Allegheny Ludlum, November 2006

or because mercury is present in the vapour form and not condensing or accumulating in situation where it is used. Nevertheless, Tungum Limited recommends that Tungum should not be used in service containing mercury. Initially, concern had been raised about galvanic action between these alloys and other materials, e.g. stainless steel fittings however, tests conducted by one of our operating companies removed these concerns. This is significant because stainless steel fittings are much less expensive than these fittings. It was concluded that these materials when used with AISI 316L fittings are suitable for this application, provided that the hardness of the ferrules is greater than that of the tube material.

7. The nickel alloys 625 and C-276 as well as Titanium do not have any known technical drawbacks. These materials are very resistant and are suitable for this service however the initial procurement cost and the long lead-time required does not make these materials preferred option for this service.

Since the main concern for this application is external and not internal corrosion, the other option explored was the possibility of having additional protection by means of an external barrier on AISI316L or AISI317L. The following options were duly considered:

- Greases designed for temporary protection during storage and shipping has been applied as a stop-gap measure. Such systems typically work well for a limited period of time. The disadvantage is that the grease would have to be re-applied on the whole system (including clamps), probably on an annual basis; therefore it is not considered a suitable long-term solution.
- Painting of stainless steel tubing in principle is a possibility, however, it should be borne in mind that painting stainless steels requires stringent procedures; special blasting grit and paint systems would be required, whereas painting small-bore tubing is rather difficult and would probably be best executed in a shop environment. The disadvantage is that the protective paint on the tubing could be damaged during shipping and reliable paint repair in the field is unlikely to be successful, hence painting is not considered a suitable option.
- Polymer sheathing has been used successfully, e.g. PVC sheathed AISI 317L tubing has been successfully used in one of our projects in the Gulf of Mexico and in spite of the onerous service conditions, the protective layer has held up very well with no signs of damage or degradation after 5 years in service. Polymers such as PVC or Polyurethane (PU) are suitable provided the specification is such that it is stabilized against UV deterioration for the service life. As with the painted tubing there is concern of damage during transportation, although the polymer layer is quite robust. AISI 316L fittings have performed well possibly due to its wall thickness, however to make this system foolproof, the ends of the tubing at the fittings have to be protected to minimise the risk of crevice, particularly in sections where there are cut back of the sheathing to install the ferrules for the fitting, which makes installation rather complicated but achievable. Installation of polymer-sheathed tubing requires the use of special tools and specially trained pipe fitters that are capable of working with this material without causing any damage. Also field repair procedures have to be in place for any maintenance work. The systems have to be pressure tested prior to wrapping the fittings to allow leak detection. The time period between construction and fittings wrapping should be minimized to avoid initiation of corrosion. Provided all of these restrictions are properly dealt with, polymer sheathed AISI 316L tubing is a viable option for this application.
- Tape wrapping with polyethylene (PE) using a suitable adhesive is also a possible option given the good experience with heat shrink sleeves on pipelines and flange assemblies. However, installation would be so complicated and labour intensive that this option is not considered suitable for this application.
- Use of high-pressure flexible hose terminated on site in accordance with manufacturers procedures and using the appropriate swaging machine to create custom lengths was also considered, the most commonly used flexible hoses consist of an inner tube of polyamide (nylon), four spiral layers of carbon steel wire and an outer sheath of polyamide (nylon). The outer layer is UV stabilized by means of carbon. Based on Gulf of Mexico experience, high-pressure flexible hoses have been used in this type of service successfully for many years, although some permeation of the fluids through the nylon will occur. It was concluded that such hoses are suitable for at least 10 years for this application provided no external damage occurs that exposes the reinforcement wires. If damage to the external sheath occurs to the extent that the reinforcement wires are exposed to the atmosphere, it is estimated that failure may occur in six

months to two years. It is obvious that the greatest risk of damage to the external sheath exists during installation. Although the hose is flexible, it is still fairly rigid to the extent that if pulled through cable trays and around sharp corners, the external sheath can easily be damaged. To avoid such damage, 100% on site inspection is required. Since damage can also occur due to dropped objects it is recommended that all flexible hoses be included in the regular (visual) inspection surveys. If damage occurs that has clearly only affected the external sheath, the hose can be repaired by a suitable wrap to avoid corrosion of the reinforcement wires, however if the reinforcement wires are corroded, the damaged section of hoses must be replaced. The requirement for visual inspection and accessibility issues coupled with the vulnerability of the flexible hoses does not make this a preferred option.

RECOMMENDATION

Having considered all the various options, using a life cycle cost analysis and proper consideration of lead-time requirement for the material as the basis for selection, we recommended to use the fire retardant and UV resistant thermoplastic polyurethane jacketed AISI 316L stainless instrument tubing for this application and have developed a fabrication specification for the polyurethane jacketed for offshore stainless steel tubing. This option was used to replace the failed tubing and also the entire AISI 316L tubing initially installed on our FPSO in the Gulf of Guinea. Currently we have almost two years of service and no leaks or other deterioration have been found during inspections.

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