Abstract

Offshore oil and gas production environments provide severe challenges in terms of materials selection and day-to-day operations. Several issues encountered during commissioning of a North Sea platform and the remedial actions are presented. Iron contamination from debris generated during topsides construction and chlorides from the marine atmosphere provided the conditions necessary for ferric chloride pitting corrosion of uncoated 316 stainless steel (SS), duplex and super duplex SS, and 6%Mo SS pipework and vessels. Several offshore cleaning/coating methods were evaluated and a new procedure for cleaning was identified that achieved the desired goal without removal of metal or affecting the corrosion resistant alloy's passive film integrity. Corrosion protection of carbon steel bolting by encapsulation was employed to stop deterioration of an improperly applied anodic coating. Insulated SS instrument tubing was susceptible to crevice corrosion and chloride stress corrosion cracking (Cl-SCC) under wet insulation at the temperatures generated by the heat tracing. Solutions were suggested to minimize such forms of corrosion. Coatings exceeding the manufacturer’s recommended thickness had been applied to several high temperature vessels and pipework to prevent SCC as well as ferric chloride pitting. The potential for coating disbondment at elevated temperatures due to high dry film thickness was evaluated through a testing program and onsite inspections.

Introduction

A platform topsides facility, shown in Figure 1, installed on a North Sea jacket, deteriorated substantially during the time between installation and the start of hookup/commissioning due mainly to the substandard coatings and workmanship. This degradation was exasperated by construction contamination and exposure to the marine environment. To safely, cost-effectively and in a timely manner remediate this situation, a rectification team was established, which included materials and corrosion specialists. Implementation of pragmatic solutions to the various issues encountered was required to ensure an on-time start-up. The required work scope entailed:

1. Bolting remediation with thermoplastic encapsulation
2. Iron and chloride contamination removal
3. Aluminum foil for heat tracing of corrosion resistant alloy (CRA) instrument tubing
4. High dry film thickness (DFT) coating qualification.

Bolting remediation with thermoplastic encapsulation

Corrosion of bolting has been long recognized as a problem for offshore platforms.(O. Andersen et al., 1996, K.P. Fischer, 2002, K.P. Fischer, 2003, I. A. Muzghi, 2004, K. Stevens, 2000, K. Stevens et al., 2003, B.M. Willis, 2000) Various remediation techniques have been used in the past including, fluoropolymer coatings, electroplating/galvanizing, and use of CRA bolting materials. At this facility, most bolts were manufactured from low alloy carbon steel to provide a good combination of high strength and reasonable cost. Zinc/nickel electroplating followed by a passivation treatment was specified to provide corrosion protection. During deck integration, it was evident that a significant quantity of bolting materials on the platform suffered corrosion due to failure and premature consumption of the electroplated "protective" coating. As most piping systems were already installed and hydrotested, it was important to avoid replacement of bolting materials unless safety or short-to-medium term operability were threatened. The corrosion product was superficial, giving an unsightly appearance to the bolts, adjacent flanges and piping components as shown in Figure 2. No pitting corrosion was observed.
However, considering the potential for future damage to adjacent contaminated materials, remedial measures were developed. Research work demonstrated that the Zn/Ni plating did not meet specification in terms of thickness and Zn/Ni ratio (incorrect plating chemistry). Therefore, the application of a thermoplastic encapsulation product to prevent water ingress for bolts operating below 90°C (194°F) was recommended. Encapsulation had been used successfully on other ConocoPhillips offshore platforms and was thus a recognized, acceptable technical solution for bolt preservation in the North Sea environment. In addition, this ensured minimized disruption to ongoing construction; therefore, no further consideration was given to alternative coatings or bolt replacement using alternative materials/coating systems.

This thermoplastic encapsulation containing corrosion-inhibiting pigments (Enviropeel™) is spray applied and maintains its mechanical properties up to 90°C (194°F) and then softens, losing strength as temperature increases to a melting temperature of 120°C (248°F). It was applied over bare metal or after preparation and application of protective coatings to the flange and associated components. For bolting materials in flanges operating at temperatures above 90°C (194°F), utilization of existing bolting materials with no additional protection was recommended. Figure 3 shows a photograph of high temperature salt encrusted bolts with no corrosion. This was considered acceptable on the basis that there would be no electrolyte (water) for most of the time and the oxygen solubility would be low at elevated temperatures. Figure 4 shows the bolts after encapsulation with the thermoplastic coating.

**Removal of surface contamination (iron and chloride) and application of surface tolerant epoxy to protect SSs from contamination**

During topsides construction, debris such as grinding dust and weld splatter was generated and settled on the surface of the pipework and vessels. In addition, hot iron particles impacted the metal surfaces as a result of grinding or welding in close proximity. Un-insulated 316, duplex, super duplex and 6%Mo SSs when exposed to this iron contamination in the presence of chlorides are susceptible to localized pitting and crevice corrosion. Examples of corrosion caused due to iron and chloride contamination are shown in Figures 5-7. A ferric chloride pit on a 316 SS pipe found pre-startup is shown in Figure 8. The comet trail seen is a result of removing the ferric chloride gel covering the pit. Therefore, a procedure was developed for cleaning and inspection of iron and chlorides on the surface of SS which met the following criteria:

1. Does not generate additional detrimental debris
2. Limited or eliminated metal removal to preserve design wall thickness
3. Removal of both iron and chloride contamination such that the surface was “paint ready”
4. Did not affect the passive film integrity of the SS

ConocoPhillips materials engineering lab and an outside lab independently tested different cleaning methods for iron and chloride contamination removal. Based on the results of these test programs, the cleaning operation proposed by ConocoPhillips was recommended as the first option due its efficient way in removing iron contamination. The tests involved intentional deposition of grinding debris on 2x22 2205 SS panels, which were then exposed to the standard NACE brine for 24 h. It was determined that the most effective abrading method involved the use of 3M™ plastic bristle disks/finger wheels. Photographs of the test panels before and after the cleaning process are shown in Figure 9. For surfaces requiring painting after the cleaning process, 50 grit bristle disks were recommended, whereas for surfaces requiring only the cleaning process, 80 grit bristle disks were found to be effective. These disks provided excellent results in testing done using simulated iron/chloride contaminated duplex SS plates in the lab and during field trials. The advantage of using plastic disks as compared to conventional abrasive tools was that they safely and effectively removed iron contamination with minimal removal of base material. The best results were obtained by uniformly sanding the contaminated surface with a minimum of two passes and a 90° direction change with each pass. Hard to reach areas such as bolts in flanges, 90° corners in bends could be cleaned using plastic finger wheels. The cleaned panels were then submitted to the Solution Method A test (10% ferric chloride, 35°C (95°F), 72 h),(ASTM G48, 2003) Again the results indicated no alteration of passivation/corrosion resistance properties of the 2205 duplex SS from using the plastic bristle disks.

On the platform, it was necessary to confirm the surfaces were clean prior to coating. Therefore, a Ferroxyl Test was performed to determine if the cleaning process needed to be repeated. The Ferroxyl Test detects presence of free iron on SS surfaces.(ASTM A380, 2006, ASTM A967, 2005) The Ferroxyl Test Solution was applied to the SS surface using a paint brush. A blue stain, appearing in about 15-30 seconds, indicated presence of iron. The solution was then removed from the surface with sponge and water as quickly as possible after testing. The same area was re-abraded using the plastic bristle disk or finger wheel, if the surface was stained. The test was conducted over a 6”x6” area; every 10 m for pipes, every 4 m² for vessels or any region where weld splatter was present. It was recognized that cleaning around bolts and other hard to reach areas was difficult to achieve with the best efforts. Therefore, this test did not apply to those areas. Photographs of panels which passed and failed the Ferroxyl Test are shown in Figure 10.
Once the vessel or pipework passed the Ferroxyl Test, chloride levels were measured at a different area nearby the Ferroxyl Test area. Chloride measurements were also conducted every 10 m for pipes and every 4 m for vessels. A portable and battery operated conductivity meter was used for detection of chlorides. If the chloride level was higher than 7 μg/cm², the surface was water washed until the salt contamination meter reading was below 7 μg/cm². The complete cleaning process has been summarized in the flowchart shown in Figure 11.

As a remedial action, a cleaning/coating program was planned to eliminate the iron contamination on the bare SS surface area across the platform. Painting of selected un-insulated SS equipment was implemented to provide a barrier against future contamination and additional corrosion protection for critical vessels and piping. However, all pipes and vessels were cleaned as per the abrasion procedure described above irrespective of whether they would be coated or not. Appropriate surface tolerant epoxies were used for un-insulated SS piping depending on the application temperatures.

### Preventing cracking of heat traced instrument lines with aluminum foil

Heat tracing had been applied directly to uncoated instrument tubing constructed from CRAs such as 316L SS and Monel. Of particular concern were the insulated instrument lines. Wet insulation would generate an aggressive environment between the base material and heat tracing which could cause pitting and crevice corrosion, leading to chloride stress corrosion cracking (Cl-SCC) at higher temperatures. (A. J. Bagdasarian *et al.*, 1997, A. Turnbull *et al.*, 2007) A procedure was generated to address the problems associated with heat tracing and insulation in direct contact with unprotected CRAs.

Corrosion Under Insulation (CUI) is a well known form of external corrosion in the oil and gas industry. (H. Ahluwalia, 2006) Traditional types of insulation, for example mineral wool, encourage external corrosion due to elevated chloride levels and inability to prevent water ingress. CUI is difficult to detect without removing sections of insulation and once initiated is difficult to control. To limit CUI offshore, insulation fabricated from glass was specified (does not absorb water, used for a wide temperature range -260°C (-436°F) to 430°C (806°F)). However, if the ends are improperly sealed or if the insulation suffers mechanical damage, there is potential for water ingress between the insulation and base material. The project specified that insulation would not be applied directly to austenitic (316L, 6% Mo), duplex or super duplex SSs and stated that a suitable coating system be applied to provide first stage corrosion protection. Where coating application was impractical, for example instrument tubing, wrapping with aluminum foil was recommended. (J.A. Richardson *et al.*, 1985) The foil acted as a sacrificial anode, corroding preferentially relative to the tubing upon water ingress. Figure 12 shows the aluminum foil applied between the instrument lines and heat tracing.

Failures have been reported in the literature for 316L SS tubing. (A. J. Bagdasarian *et al.*, 1997) These failures occurred as a result of both pitting and crevice corrosion and in some cases led to Cl-SCC. Failures were also reported for 316L SS instrument tubing in direct contact with heat tracing and insulation on another ConocoPhillips offshore platform. Failures have also been reported for Monel alloy 400 in seawater at ambient temperature. (D.G. Tipton *et al.*, 1980) However, at 50°C (122°F), the susceptibility to Cl-SCC decreased.

For rectification of CRA pipework and valves that had heat tracing and/or insulation applied to unpainted surfaces, the following actions were recommended:

1. Remove heat tracing tape from unpainted valves/pipework, or
2. Re-route heat tracing tape from unpainted pipework/valves to those that are painted, or
3. Paint valves/pipe sections in accordance with the internal specification. This could involve removing the heat tracing already applied to unpainted materials, painting under the heat tracing, then reinstating the heat tracing.
4. Wrap with aluminum foil if under insulation, or
5. Permanently separate heat tracing from the surface of the component. Grommet sleeves may be acceptable for use in this application.

Where heat tracing had been applied (and is required) directly to any SS instruments and manifolds without being painted the following was recommended:

1. Remove insulation,
2. Remove adhesive foil on top of heat tracing,
3. Remove heat tracing,
4. Clean surfaces to remove any chlorides and iron contamination,
5. Apply aluminum foil directly to instrument tubing,
6. Reapply heat tracing,
7. Reapply insulation where required by process.
Where heat tracing had been applied (and is not required) directly to 316L instruments, instrument tubing and/or manifolds the following recommendations were made:

1. Remove heat tracing tape from unpainted materials, or
2. Re-route heat tracing tape from unpainted sections to those that are painted, or
3. Wrap with aluminum foil if under insulation, or
4. Permanently separate heat tracing from the surface of the component. Grommet sleeves may be acceptable for use in this application.

It was recommended that all 316L, 22% Cr duplex, 25% Cr super duplex and 6% Mo SS components that were unpainted, heat traced and/or insulated be rectified before start-up. All 316L SS unpainted/unprotected instruments, instrument tubing and manifolds, not heat traced and not insulated were to be cleaned to remove any iron/chloride contamination, and inspected. All 316L SS instrument tubing that was unpainted, heat traced and insulated would be rectified prior to start-up.

**Evaluation of excessively thick coatings’ ability to survive high temperature service**

Excessively high dry film thickness (DFT) readings were reported for high temperature epoxy phenolic external coatings on several insulated vessels on the offshore platform. This particular epoxy phenolic has been commonly used to internally line tanks and vessels. It has also been used successfully for a number of years as an external coating under insulation, where immersion grade coatings are required. These coatings were applied as per the appropriate coating standards. (NORSOK Standard M-501, 2004) However, the coating thicknesses in some areas had been applied in excess of the manufacturer’s recommendations. Thickness values in excess of 1000 μm were measured in some spots, whereas 2-coat thickness values of 250-400 μm were deemed acceptable as per the coating specification. Four of these vessels (three made from duplex SS, one made from carbon steel) operated at temperatures above 95°C (203°F), which is the upper temperature limit for use of the epoxy phenolic in constant immersion. Where over-applied, these coatings could crack prematurely and detach at high temperatures, creating conditions which could have the potential to degrade the base material (Cl-SCC). The problems with thick coatings are; high stresses, solvent entrapment resulting in blistering and loss of adhesion to the substrate, and longer curing times. The possibility of removing the coating by abrasive blasting and reapplying was considered, but was not found to be feasible given the impending start-up date and the cost of a major, offshore coating campaign. Alternatively, delaying replacement of coatings at a future opportune moment was also not an option since coating failure/flake-off could result in corrosion/cracking of the base material. The possibility of rectifying these coatings by reducing the thickness was also looked into, but was not implemented since the inherent coating stress due to high thickness would be present even if the DFT was reduced by removal of part of the coating. An example of a primer coating applied to an offshore vessel is shown in Figure 13.

Therefore, it was proposed that 14 coupons of carbon steel and duplex SS coated with these epoxies at high thicknesses (350, 600, 750 and 900 μm) be tested at various temperatures (the duplex SS were exposed to 70°C (158°F) or 95°C (203°F) for 1 week followed by 1 week at 112°C (234°F), the carbon steel coupons were exposed to 70°C (158°F) for 1 week followed by 1 week at 112°C (234°F) and 1 additional week at 135°C (275°F)). Adhesion and hardness tests were taken at the end of each heating cycle, as long as the coupon had not failed. The response of these panels would qualify continued use of the existing coatings offshore. Exposure testing was done at two independent labs (Lab 1, Lab 2). At both labs, two panels (one duplex SS, one carbon steel) were painted and sent to the other lab for the exposure testing. All carbon steel panels passed the 3-week exposure and all duplex SS panels passed the 2-week exposure tests at the Lab 2 facility. At the Lab 1 facility, all the coupons passed the 1-week 70°C (158°F) exposure test. However, coatings on 3 coupons (1 carbon steel, 2 duplex SS) cracked and completely disbonded on the 4th day of the 2nd heating cycle at 112°C (234°F). The failed duplex SS samples had the highest DFTs (750, 850 μm). Three other coupons had very light cracking at the coating edges on the last day of testing. Low adhesion values were recorded for the duplex SS panels at the start of the Lab 2 tests. All the results obtained from testing at the two labs are shown in Table 1 and 2. Photographs of a carbon steel panel after the 3 week test and a duplex SS panel after the 2 week test are shown in Figures 14-15 respectively.

Epoxy phenolic coatings used here have temperature limitations for constant immersion service. However, based on the results from the two test programs, it is evident that proper surface preparation and adequate curing could ensure that even high DFT coatings survive high temperature exposure. The tests done at the two labs indicated that these coatings would provide corrosion protection up to the 135°C (275°F) with an upper thickness limit of 600 μm. Coating thicknesses above this value were only present on the lower temperature vessels. Coating discoloration is a recognized issue for such epoxy systems at these temperatures, but would have no detrimental effect on coating performance and should not be an event that drives the inspection program. Instead, periodic inspection of high millage regions (along with minor repairs if necessary) was suggested so as to ensure these
coating systems fulfilled their life expectancy of 15-20 years with minimal maintenance. A risk based inspection program based on probability and consequence of failure, was developed for cleaning and painting of the high DFT pipework and vessels. Similar risk based maintenance management systems for offshore protective coatings have been recently published in the literature. (S.B. Axelsen et al., 2009, S.B. Axelsen et al., 2010, S.B. Axelsen et al., 2010) On this platform, the high priority (high temperature, high DFT) vessels were inspected on a daily basis for temperature related coating cracking, during the startup period. As expected, only minor discoloration was observed. No cracking of the coatings was found on the offshore vessels. These coatings have now been in service for approximately 2 years without incident.

Summary
Based on field and laboratory trials, the following recommendations were made for remediation of the problems encountered during the startup of the offshore platform:

1. Bolting remediation with Enviropeel addressed corrosion of bolting materials from premature consumption of the Zn/Ni electroplating. “Enviropeel” coating had been used successfully on other ConocoPhillips platforms and was thus a recognized, acceptable technical solution for bolt preservation in the North Sea environment.

2. Removal of surface contamination (iron and chloride) using plastic bristle disks was an innovative solution developed through lab testing for cleaning of SS surfaces.

3. Cracking of insulated and heat traced instrument lines was prevented using aluminum foil. Heat tracing applied directly to uncoated CRA instrument tubing created crevices, which caused localized corrosion. Therefore, wrapping with aluminum foil was utilized to provide cathodic protection.

4. Qualification of high DFT coatings for continued use offshore for high temperature service was done using a short-term research program conducted in conjunction with the coating vendor. The results of the testing indicated that these coatings could survive the operating temperature; thereby avoiding the time, labor and money involved in replacing these coatings.

Acknowledgements
The authors wish to thank the ConocoPhillips management for allowing them to present and publish this paper. Special thanks are also given to the other members of the offshore rectification team for their invaluable technical contributions.

Nomenclature
- **Cl-SCC**: Chloride stress corrosion cracking
- **CRA**: Corrosion resistant alloy
- **CUI**: Corrosion under insulation
- **DFT**: Dry film thickness
- **SS**: Stainless steel

References
Table 1. Results of coating testing at Lab 1.

<table>
<thead>
<tr>
<th>Plate</th>
<th>Material</th>
<th>Target, Actual DFTs (μm)</th>
<th>Hardness</th>
<th>Adhesion (psi)</th>
<th>Temp (°C)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>CS</td>
<td>350, 300</td>
<td>92, 93, 98</td>
<td>2100</td>
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<tr>
<td>2</td>
<td>CS</td>
<td>350, 375</td>
<td>95, 95, 95</td>
<td>3500</td>
<td>70, 112, 135</td>
<td>Discolored, no cracks</td>
</tr>
<tr>
<td>3</td>
<td>CS</td>
<td>600, 575</td>
<td>89, 95, 95</td>
<td>1450</td>
<td>70, 112, 135</td>
<td>Discolored, no cracks</td>
</tr>
<tr>
<td>4</td>
<td>CS</td>
<td>750, 625</td>
<td>86, 95, 95</td>
<td>2600</td>
<td>70, 112, 135</td>
<td>Light cracks – top edge</td>
</tr>
<tr>
<td>5</td>
<td>CS</td>
<td>900, 750</td>
<td>92</td>
<td>-</td>
<td>70, 112</td>
<td>Discolored, no cracks</td>
</tr>
<tr>
<td>6</td>
<td>CS</td>
<td>600, 575</td>
<td>89</td>
<td>-</td>
<td>70, 112</td>
<td>Sent to Lab 2</td>
</tr>
<tr>
<td>7</td>
<td>DSS</td>
<td>350, 600</td>
<td>82, 95</td>
<td>1050</td>
<td>70, 112</td>
<td>Discolored, no cracks</td>
</tr>
<tr>
<td>8</td>
<td>DSS</td>
<td>350, 525</td>
<td>78, 95</td>
<td>2000</td>
<td>70, 112</td>
<td>Discolored, no cracks</td>
</tr>
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<td>9</td>
<td>DSS</td>
<td>600, 575</td>
<td>89, 93</td>
<td>1425</td>
<td>70, 112</td>
<td>Light cracks – top edge</td>
</tr>
<tr>
<td>10</td>
<td>DSS</td>
<td>750, 700</td>
<td>81, 95</td>
<td>2050</td>
<td>70, 112</td>
<td>Cracking – bottom edge</td>
</tr>
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<td>11</td>
<td>DSS</td>
<td>900, 850</td>
<td>85</td>
<td>-</td>
<td>70, 112</td>
<td>Cracked during 2&quot; cycle¹</td>
</tr>
<tr>
<td>12</td>
<td>DSS</td>
<td>600, 490</td>
<td>93, 95</td>
<td>1900</td>
<td>70, 112</td>
<td>Discolored, no cracks</td>
</tr>
<tr>
<td>13</td>
<td>DSS</td>
<td>600, 525</td>
<td>92</td>
<td>-</td>
<td>70, 112</td>
<td>Cracked during 2&quot; cycle¹</td>
</tr>
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<td>14</td>
<td>DSS</td>
<td>600, 575</td>
<td>90</td>
<td>-</td>
<td>70, 112</td>
<td>Sent to Lab 2</td>
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</tbody>
</table>

Notes:  
1. Hardness values were measured after each heating cycle.  
2. Adhesion values were taken after completion of all heating cycles. All failures were glue failures. Strength values were greater than 750 psi, the minimum expected adhesion for a cured coating.  
3. Three plates (#5, #11, #13) cracked 4 days into 2nd cycle; these panels were removed.  
4. Plates #6, #14 painted in Lab 2.

Table 2. Results of coating testing at Lab 2.

<table>
<thead>
<tr>
<th>Plate</th>
<th>Material</th>
<th>Target, Actual DFTs (μm)</th>
<th>Adhesion (psi)</th>
<th>Temp (°C)</th>
<th>Comments</th>
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<td>1</td>
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<td>350, 386</td>
<td>1233</td>
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<td>2</td>
<td>CS</td>
<td>350, 396</td>
<td>-</td>
<td>70, 112, 135</td>
<td>Discolored, no cracks</td>
</tr>
<tr>
<td>3</td>
<td>CS</td>
<td>600, 670</td>
<td>1305</td>
<td>70, 112, 135</td>
<td>Discolored, no cracks</td>
</tr>
<tr>
<td>4</td>
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<td>750, 912</td>
<td>1160</td>
<td>70, 112, 135</td>
<td>Discolored, no cracks</td>
</tr>
<tr>
<td>5</td>
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<td>900, 997</td>
<td>1305</td>
<td>70, 112, 135</td>
<td>Discolored, no cracks</td>
</tr>
<tr>
<td>6</td>
<td>CS</td>
<td>600, 696</td>
<td>-</td>
<td>70, 112</td>
<td>Sent to Lab 1</td>
</tr>
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<td>7</td>
<td>DSS</td>
<td>350, 419</td>
<td>290</td>
<td>70, 112</td>
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</tr>
<tr>
<td>8</td>
<td>DSS</td>
<td>350, 418</td>
<td>290</td>
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<td>Discolored, no cracks</td>
</tr>
<tr>
<td>9</td>
<td>DSS</td>
<td>600, 621</td>
<td>290</td>
<td>70, 112</td>
<td>Discolored, no cracks</td>
</tr>
<tr>
<td>10</td>
<td>DSS</td>
<td>750, 682</td>
<td>290</td>
<td>70, 112</td>
<td>Discolored, no cracks</td>
</tr>
<tr>
<td>11</td>
<td>DSS</td>
<td>900, 710</td>
<td>290</td>
<td>70, 112</td>
<td>Discolored, no cracks</td>
</tr>
<tr>
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<td>600, 623</td>
<td>290</td>
<td>95, 112</td>
<td>Discolored, no cracks</td>
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<tr>
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<td>DSS</td>
<td>600, 620</td>
<td>290</td>
<td>95, 112</td>
<td>Discolored, no cracks</td>
</tr>
<tr>
<td>14</td>
<td>DSS</td>
<td>600, 603</td>
<td>-</td>
<td>70, 112</td>
<td>Sent to Lab 1</td>
</tr>
</tbody>
</table>

Notes:  
1. Adhesion was measured at the start of the tests. Low adhesion (290 psi) was reported for coatings on thin duplex SS plates. All 14 plates showed improved values between 2176-2901 psi at the end of the tests.  
2. Plates #6, #14 painted in Lab 1.
Figure 1. Photograph of the offshore platform.

Figure 2. Acceptable nut in a corroded batch.

Figure 3. High temperature salt encrusted bolts showing no corrosion.

Figure 4. Bolts encapsulated with Enviroleel™.

Figure 5. Iron and chloride contamination on offshore pipework showing corrosion pits.

Figure 6. Iron and chloride contamination on a separator vessel prior to cleaning and coating.
Figure 7. Close-up photograph of iron and chloride contamination on a SS vessel.

Figure 8. Ferric chloride pit in 316 SS discovered pre-start up, i.e. at only ambient temperature.

Figure 9. Photographs showing a 2205 duplex SS panel after intentional iron and chloride contamination and after cleaning in the lab.

Figure 10. Photographs showing the result of Ferroxyl testing on contaminated and cleaned 2205 duplex SS panels.
Figure 11. Flowchart showing the complete process for removal of iron and chloride contamination.

Figure 12. Aluminum foil applied between the instrument lines and heat tracing.

Figure 13. Primer applied to an offshore vessel.

Figure 14. Carbon steel panels coated with epoxy phenolic after high temperature exposure.

Figure 15. Duplex SS panels coated with epoxy phenolic after high temperature exposure.