Buried and submerged pipelines are protected from external corrosion by a coating system, which is considered passive. Coatings are practically always applied to pipe lengths in specialized coating plants, and continuity of coverage is ensured after girth welding through field joint coatings (FJC). Cathodic protection (CP) is an essential, complementary, “active” protection system aimed at preventing corrosion at coating defects, where the pipe steel surface is exposed to the corrosive electrolytic environment. As long as coatings remain bonded to steel and CP is correctly applied, monitored, and maintained, no corrosion risk exists.

The majority of known corrosion cases result from disbonding of coatings, which may prevent access of the cathodic protection current to steel. The cause of failure, known as the “CP current shielding effect,” appears to be a concern limited to buried pipelines onshore. Cases of corrosion and stress corrosion cracking (SCC) on old buried pipelines coated “on the ditch” with coal tar or asphalt enamels or cold-applied tapes have been known for a long time. No case of external corrosion of pipelines immersed in seawater has been detected so far using in-line inspection (ILI), despite, most likely, the existence of some coating disbondment. Despite the assumption of some coating disbondment in seawater, corrosion protection is maintained, probably because the high conductivity and homogeneity of seawater make it easier for the CP current to access the exposed steel and protect it.

Summaries of our company’s past experience with various kinds of pipeline coatings have been presented in previous papers. In particular, at the 16th International Conference on Pipeline Protection in Paphos, the authors presented a paper on failures recently discovered on “newer” coatings.
such as heat-shrinkable sleeves, three-layer polyethylene (PE) coatings, and fusion-bonded epoxy (FBE) coatings. The present article first updates and completes the information presented at the Paphos conference on the recent cases of coating failures encountered. It also summarizes the results obtained from some laboratory test programs aimed at trying to explain the problems for improving the future choices and the specifications of the company.

Recent Feedback on Disbonding of Pipeline Coatings

Various practical case studies follow. Cases related to heat-shrinkable sleeves (HSS) used for field joints and which overlap the factory-applied 3-layer PE/polypropylene (PP) are the most important as far as corrosion is concerned. Even if the problems related to loss of adhesion of 3LPE/PP coatings do not lead to significant corrosion, the phenomenon must be better understood to prevent the risk for the future.

Heat shrinkable Sleeves Used for Field Joint Coating

Recent in-line inspections (ILI) carried out on a series of buried pipelines have shown massive disbonding of HSS with significant corrosion underneath after 10 to 15 years of operation in the ground. These coating failures and subsequent corrosion have been noticed principally at moderately elevated temperatures (about 50–60 C [122–140 F]) and on coating systems that had been applied to a wire brush-cleaned surface specified at St 3 cleanliness level (“SSPC SP 3, Power Tool Cleaning”), with or without application of a liquid epoxy primer before the PE/PP. Specific examples of such failures are given below.

18-Inch Oil Pipeline in Gabon

In this case, presented earlier, external corrosion was detected through ILI on the first 15 km, which is the hottest side (>55 C [131 F]) of the 18-inch Rabi-Batanga oil pipeline, after 15 years of operation in the ground. The pipeline is buried in wet, compacted sand (pH of sample, 5.4). Heat-shrinkable sleeves were the hot-melt adhesive type and were applied on a fast-curing liquid epoxy (of nominal maximum operating temperature 80 C [176 F]). Wire brush cleaning as per St 3 was used for surface preparation. The application was fully surveyed by a company inspector.

Massive disbonding of HSS on the steel surface together with poor bonding of HSS on the 3LPE plant-applied coating at the overlaps had allowed water to penetrate at the steel surface, leading to corrosion because of the “CP shielding effect” (Fig. 1).

Further excavations of the pipeline revealed that the HSS residual adhesion to the steel was also practically zero on sections at lower operation temperature (down to 35 C [95 F]) but without significant corrosion.

16-Inch Oil Pipeline in Syria

ILI operations carried out on a 16 inch x 7.1 mm wall thickness oil export pipeline operated in Syria for about 12 years have revealed severe external corrosion at many girth weld areas. These areas had been coated with HSS (hot-melt adhesive type) applied directly to a wire brush-cleaned surface, without liquid epoxy primer (Fig. 2). Excavations have confirmed the indications of ILI and revealed several corrosion craters underneath the surface of the field joints with significant presence of mill scale. Corrosion is clearly due to disbondment of HSS. The surface preparation was poor and the HSS overlap on the PE plant-applied coating was too small (1 cm).

The soil is very aggressive (brackish water with a chloride concentration of 2 g/liter) and crystals of salt were observed under the disbonded HSS.
and on a 6-inch oil pipeline in France (Paris basin). Again, the operating temperature was about 50 C [122 F] in both cases.

**Disbonding of 3LPE/PP Used in Plant-Applied Coatings**

Massive losses of adhesion of 3LPE coatings between the epoxy layer and the steel after 10 to 15 years’ operations have been observed since 2004 through excavations carried out after the detection of corrosion at field joints under disbonded HSS. The disbondments of 3LPE have been noticed most often when the operating temperature of the pipeline is about 50–60 C (122–140 F) in wet environments. So far, no significant corrosion has been found underneath the disbondment of the 3LPE.

**18-Inch Oil Pipeline in Gabon**

Also presented earlier,\(^1\) disbonding of a 3LPE coating occurred on the same 18-inch Rabi-Batanga pipeline in Gabon. The coating was a low-density PE. It was applied partly by the side extrusion process (with PE adhesive applied by extrusion) and partly by the longitudinal extrusion process (with PE adhesive applied by powder). The application was in compliance with the company specification requiring a minimum of 70 micrometers FBE beneath the PE.

The 3LPE plant-applied coating generally appeared to be correct externally but was found fully disbonded between the FBE and steel when cut for inspection with a tool at the excavation locations in the hottest part of the pipeline. Except for the presence of a layer of magnetite on the steel surface, no significant corrosion of the steel was noticed. Excavations showed that in a few cases, where some minor corrosion was reported by ILI on a few pipe lengths, the PE coating was found longitudinally

**Other Cases**

Similar cases were discovered recently, again using ILI, on the 12-inch Coucal-Rabi pipeline, again in Gabon.

**Table 1: Test on 3LPE Coated Pipe Samples Stored During 15 Years**

<table>
<thead>
<tr>
<th>Tests</th>
<th>Temperature of test</th>
<th>Longitudinal extrusion</th>
<th>Side extrusion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average peel strength</td>
<td>23 C (73.4 F)</td>
<td>94 ± 9</td>
<td>226 ± 34</td>
</tr>
<tr>
<td></td>
<td>60 C (140 F)</td>
<td>38 ± 3</td>
<td>142 ± 13</td>
</tr>
<tr>
<td>Cathodic disbonding @ - 1.5 V, 28 days (radial length in mm)</td>
<td>23 C (73.4 F)</td>
<td>6.3 ± 0.7</td>
<td>6.6 ± 0.4</td>
</tr>
<tr>
<td></td>
<td>60 C (140 F)</td>
<td>32.2 ± 1.6</td>
<td>28.6 ± 4.1</td>
</tr>
</tbody>
</table>

---

*Fig. 2: Heavy corrosion under disbonded HSS (16-inch Syria)*

*Fig. 3: Disbonding of 3LPE at 35 C ([95 F] 18-inch Gabon)*
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cracked and open at the 3 o’clock and 9 o’clock positions. Measurements on PE samples taken at these locations revealed a significant thermal aging effect (as shown by loss of elongation at break, increase of viscosity, Shore D hardness and IR spectrum).

In addition to the details previously given,\textsuperscript{10} it has been further noticed that loss of adhesion existed at temperatures as low as 35 C (95 F), as shown in Fig. 3. In this case, as compared with what was discovered at higher temperatures, the epoxy primer was more visible and no magnetite had been formed. Also, it has been demonstrated that this loss of bonding occurred with the two supplies of coated pipes, with two different coating processes and with two different epoxy powders. Peel strength and cathodic disbondment measurements carried out on spare pipes that had been stored directly exposed to UV and atmospheric equatorial conditions gave the results summarized in Table 1, which demonstrates again that the loss of adhesion in the ground is related to exposure to soil conditions (especially water diffusion). It is also notable that peel strength is much higher with lateral extrusion as compared with longitudinal extrusion (the difference is related to the type of adhesive) but that cathodic disbondment is of the same order of magnitude (no significant difference between the two epoxy powders), with the value measured at 60 C (140 F) being very high.

Other Cases
Local disbondment has been observed on the 16-inch Syrian oil pipeline on which severe corrosion was found under HSS (Fig. 4). In France, a short length of pipeline with a 3LPP coating operating at ambient temperature has suffered complete loss of adhesion without any corrosion. In this case, because all other inspected parts in close vicinity did not show disbondment, this observation tends to demonstrate that this loss of adhesion could be due to a specific application problem.

In Indonesia, a section of a 3LPP coated offshore pipeline (with concrete weight coating) operating at about 80 C (176 F) has been cut out for inspection related to internal corrosion. Disbondment of 3LPP from the steel was observed, showing that disbondment seems to be possible offshore also.

Laboratory Studies and an Engineering Approach
A Parametric Study of the “CP Shielding Effect” under Disbonded Coatings
Gaz de France (Direction de la Recherche) and Total have carried out studies in the Gaz de France laboratories to assess the influence of the main parameters governing the corrosion rate underneath a simulated coating disbondment. In particular, the study assesses corrosion as a function of the distance from the point where a direct contact exists with the external electrolyte. Parameters studied were the height of the gap between the steel and the simulated disbonded coating, whether the water was stagnant or changed, the resistivity of water, the application of various levels of cathodic protection, and the absence of cathodic protection. All tests were carried out at ambient temperature. The main results are discussed below. More details may be obtained in published papers.\textsuperscript{11,12,13}

The test plan is summarized in Table 2. The detrimental effect of renewal of water was clearly demonstrated. In the case of stagnant water, the corrosion rate becomes practically zero, with or without cathodic protection within a few centimeters of the artificial coating defect. Of course, this testing does not take into account any possible development of microbiologically induced corrosion (MIC) that could occur in the actual situation. This result is easily explained by consumption of dissolved oxygen through the corrosion process. Any renewal of water increases the corrosion rate when the distance from the artificial defect increases, even when cathodic protection is applied. Some posi-
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Maximum about 0.7 mm/yr at 50 °C (122 °F).

Field Joint Coatings

It is believed that disbonding of HSS may be due to surface preparation by brush cleaning and the effect of higher temperature. Corrosion under disbonded HSS may be due to:

- the penetration of water through disbonded overlaps on plant coating;
- the shielding effect preventing CP, together with a too weak “true” level of CP; or
- an increase in the corrosion rate because of the temperature.

For the time being, it has been decided (at our company) to require, as a minimum before HSS application, Sa 2 1/2 abrasive blast cleaning of girth welds and a liquid epoxy primer applied for onshore buried pipelines or when the temperature is higher than 50 °C (122 °F).

However, the general trend is to apply, instead of HSS, liquid polyurethane (PUR) or epoxy-modified polyurethane as a field joint coating onshore, which is currently being done on a major gas pipeline in construction in Yemen (Fig. 5).

The system used a PUR-type product designed for 80 °C (176 °F) maximum operating temperature. The application parameters, equipment, and personnel had been accepted after a full qualification process comprising a Procedure Qualification Trial (PQT) at the coating application contractor premises and verification in the field at the start-up through a Pre-Production Trial (PPT).

Tests carried out on samples taken from the qualification trials were carried out by a third party laboratory, mainly based on measurement of adhesion by pull-off test as per ISO 4624 and cross-cut tests before and after immersion in tap water at various temperatures (up to 80 °C [176 °F]) and after various durations.

![Fig. 5: FJC with epoxy-modified PV applied on 3LPE-coated pipes](image-url)
(up to 28 days). Figure 6 illustrates such a series of pull-off tests. As shown in Table 3, values obtained on the PE plant coating as well as directly on the steel surface were found to be fully acceptable when the parameters of application were optimized (especially the substrate temperature). Surface preparation was abrasive blast cleaning to Sa 2 ½ on steel and abrasion without any complementary treatment on the PE.

In addition, Total is launching a comparative program for an in-depth study of various field joint coatings (PE/PP-based HSS, liquid PUR or epoxy, flame sprayed PE/PP, etc.), especially through hot water resistance testing and evaluation of the compatibility of the HSS with plant coatings in wet environments. For the HSS, two surface preparation levels will be tested: Sa 2 ½ (blasting to near white metal, SSPC-SP 10) and St 3 (very thorough power tool cleaning, SSPC-SP 3 level of cleaning). For liquid products, various surface treatments for the plant-applied coating will be tested: with and without oxidative flame and/or other proprietary treatments. Tests will consist of: cathodic disbonding (28 days at 23 C and 80 C [73 F and 176 F], and 48 hrs at 65 C [149 F]); peel tests on steel and plant coating at 23, 60, and 80 C (for PP only); impact tests per ASTM G14; immersion tests for 28 days in deionized water at 40 (104 F), 60, and 80 C; and, after immersion, peeling tests on steel and overlap. Total will be happy to share this program with any interested party.

**Efforts to Explain Disbondment Problems of 3LPE/PP Coatings**

Possible explanations for disbonding of 3LPE are

- water and oxygen diffusion through PE;
- water saturation and diffusion in FBE layer, depending on the type of epoxy;
- superficial corrosion of steel surface forming magnetite;
- all these steps being accelerated by temperature; and
- the possible effect of internal stresses in PE/PP due to the thermal history during application, which could help explain why such massive disbondment does not occur with FBE coatings. (FBE is not subject to thermal aging during application.)

Significant corrosion under disbonded 3LPE only occurs when it is also cracked due to thermal ageing, which leads to a significant gap between the disbonded coating and steel. The gap allows renewal of aggressive species and the CP current shielding effect.

Since 2006, the efforts contributing to the explanation of this phenomenon have concentrated on the following.

- Launching of a fundamental study as Ph.D. work on adhesion mechanisms of epoxy, as illustrated in another paper presented at the 17th International Conference on Pipeline Protection\(^{15}\)
- Participation in a study on the development of a new accelerated test ensuring a better qualification that could predict long term behavior (carried out for EPRG, European Pipeline Research Group). Conventional peeling tests and cathodic disbonding tests used up to now failed for such a prediction. This study is still running and the results are confidential for the time being
- A study of water sensitivity of six epoxy powders, carried out by IFP (French Institute of Petroleum). The

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**Table 3: Adhesion Tests After Immersion for 28 Days of PE Coated with Liquid Applied PU-type at FJC**

<table>
<thead>
<tr>
<th>Water temperature</th>
<th>Adhesion on steel (MPa)</th>
<th>Adhesion on abraded PE (MPa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>23 C (73.4 F)</td>
<td>15 to 20</td>
<td>5 to 15</td>
</tr>
<tr>
<td>60 C (140 F)</td>
<td>15 to 20</td>
<td>5 to 11</td>
</tr>
<tr>
<td>80 C (176 F)</td>
<td>15 to 20</td>
<td>5 to 10</td>
</tr>
</tbody>
</table>
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Extracted from NACE document “Coating Failure Definitions in Relation to CP”

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results of these tests are summarized in a paper also presented at the 17th International Conference on Pipeline Protection.\textsuperscript{16}

**Hydrothermal Aging of LDPE**

Thermal aging of various PE materials (low density stabilized by ethylene vinyl acetate (EVA) or not, 2 types of medium density) from various suppliers has been studied in wet conditions, whereas the present methods used for qualification are restricted to dry conditions. The question was: Does physico-chemical thermal aging happen to PE up to 100 °C (212 °F) in water?

The tests were carried out by Korrosionstechnik Heim. The following test conditions were used: dry air at 100 °C (212 °F); demineralized water at 60 (140 °F), 80 (176 °F), and 100 °C; and air saturated with water vapor at 60 and 80 °C. The effect of aging was assessed using elongation and tensile strength at break and Melt Mass Flow Rate (MFR). No significant change was noticed after 5,000 hours of testing for all products and all test conditions. Consequently, no explanation has been given so far for what was noted on the Rabi pipeline where cracking of PE topcoat in some locations led to corrosion. Loss of the EVA additives is still the proposed answer, but not a proven explanation. A bad batch of PE could be involved in this issue.

**Conclusion: Present Situation and Future Work**

The major corrosion problems are related to disbondment of heat-shrinkable sleeves applied on field joints of buried pipelines. For Total, abrasive blast cleaning is now mandatory before application of HSS and not only “recommended” for new onshore pipelines. In addition, the general trend is to apply, instead of HSS, liquid polyurethane (PUR) or epoxy for field joint coating onshore.

It is of utmost importance to demonstrate whether an improvement of the adhesion safety margin of 3LPO coatings is possible or not. If not, modification of Total’s basic choice could be changed in favor of FBE, in spite of the better mechanical resistance of 3LPO coatings (generally considered as a plus by pipe laying contractors). Parameters related to the composition of epoxy powders have been studied. Methods such as measurement of “Wet Tg” and the use of two-layer FBE/adhesive coatings are very promising approaches from lab studies. However, the differences noted in water intake do not correlate with the severe loss of adhesion of the coating when immersed in water, especially when water temperature is...
above ambient. For the time being, the following criteria have been introduced in Total’s general specifications for selection of epoxy primer: water absorption lower than 10% after 28 days at 80°C and “Wet Tg” greater than maximum operating temperature +10°C above the operating temperature.

The future work necessary for a better knowledge of the problem of 3LPO disbondment will be researched through a continuation of the studies at IFP, especially on test samples taken from actual pipes recently coated for various projects, and also on other epoxy powders and surface preparation systems. The Ph.D. work launched to better understand the mechanism of bonding of epoxy to steel will address factors such as mechanical vs. chemical anchor, surface preparation and treatment, and internal stresses within the coating. In addition, the study carried out in the U.S. on the internal stresses will be highly profitable for the development of knowledge.17

Continuation of field experience feedback will be organized in order to better know the influence of parameters such as temperature or soil humidity. All possible efforts will be made to push operating subsidiaries to perform excavations and field measurements in order to contribute to and assess correlations between disbondment and soil and operating parameters.

A more relevant accelerated aging test allowing a better prediction of long term behavior remains to be established (especially through EPRG collaboration) and implemented in the future revision of ISO 21809 standards currently on the way of completion based on a conventional approach.

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Marcel Roche graduated from INSA (Institut National des Sciences Appliquées) de Lyon and ENSPM (Ecole Nationale du Pétrole et des Moteurs). He specialized in corrosion from his first professional occupation in 1970 within Technip and IFP (Institut Français du Pétrole), then for Elf Aquitaine, covering Oil Refining and Oil & Gas production activities. He became Head of the Corrosion Department of TotalFinaElf, now Total SA, for Upstream after the merger in October 2000. He participates in a number of professional organizations for the corrosion protection industry. He is chairman of Cathodic Protection working parties in CEFRACOR (France) and EFC (European Federation of Corrosion), Convenor of CEN TC219 WG5 on Qualification and Certification of Personnel in Cathodic Protection and leader of ISO TC67 SC2 WG14-3 on Field Joint Coatings. He is Certified AFAQ AFNOR Compétence level 3 (expert) in Cathodic Protection for Land and Marine applications.
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