CORROSION AT ISOLATING JOINTS DUE TO CATHODIC PROTECTION

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Abstract

Application of cathodic protection generally provides protection from corrosion and ensures safe operation of pipelines without leaks for many years. Two separate corrosion investigations are discussed where rapid corrosion occurred repeatedly at the same location in each case, in the vicinity of an insulating flange / joint due to stray current effects.

The results of a failure analysis are discussed whereby it was demonstrated that the most credible corrosion mechanism was internal stray current, caused by cathodic protection applied to the pipeline. Three corrosion mechanisms were considered to have the potential to account for the internal damage: oxygen corrosion, microbial-influenced corrosion and stray current corrosion. Detailed study of these mechanisms established that only stray current corrosion could account for the rate of corrosion.

For both failures, the source of the stray current and the path taken by the current are described, along with recommendations for remedial action and monitoring.

1 Introduction

Cathodic protection generally provides protection from corrosion to buried and immersed pipelines and ensures safe operation without meaningful metal loss or integrity issues for many years. However, when applying cathodic protection, care should be taken to avoid interference effects; this might be interference to nearby third party assets or to other structures within a single site where isolation has been installed. The issue is addressed in BS EN 12954 [1], with measures included during the design stage (e.g. selection of groundbed location), during installation (checks that all other structures have been identified) and during commissioning (measurements on other structures).

The issue of effective electrical isolation and pipelines carrying low resistivity water phase is identified in BS EN 14505:2005 [2]. However, the standard does not point out the corrosion damage that can occur at isolating joints. The ISO 15589-1 also includes a section on electrical isolation and points out that if there are any electrically conductive fluids internal coating of the is required to avoid interference-current corrosion. Where there is severe interference there can be rapid metal loss leading to loss of pipe integrity.

This paper provides a brief description of the issue and two examples where corrosion damage occurred.

2 Background

For internal stray current corrosion of a pipeline to occur, all three of the following must be present:

- An isolation joint (IJ), isolation flange (IF) or spool piece that interrupts the pipeline electrical continuity.
- An internal conductive electrolyte to provide an alternative and continuous path or ‘bridge’ for the stray current to cross from one side of the isolation joint to the other.
- A DC voltage difference between the two sides of the isolation joint.

This combination effect is illustrated in Figure 1; stray current corrosion will only occur if all these three features are present.

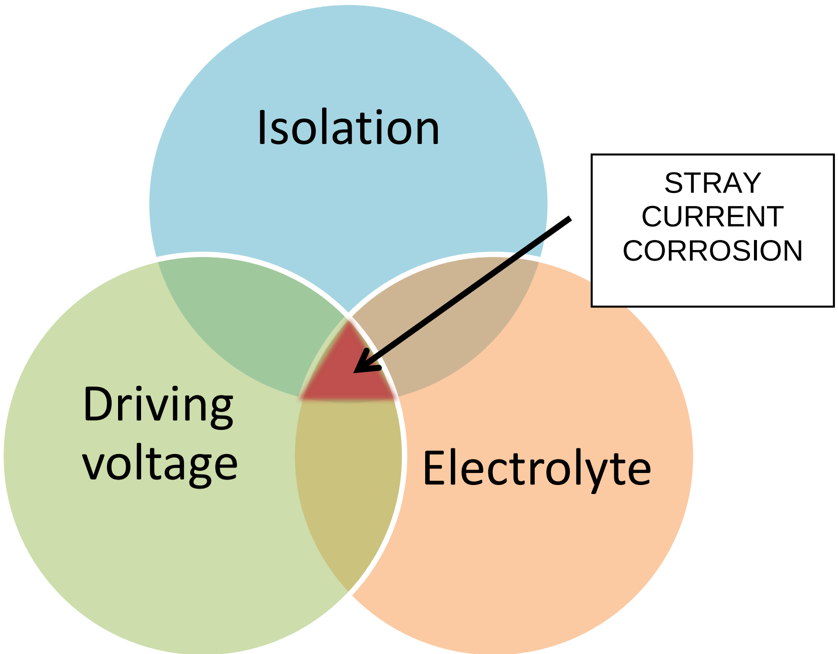

Figure 1. Stray current corrosion

Stray current is defined as electric current that *strays from its intended path.* Stray current corrosion is caused by the electrical current discharge as it leaves the surface of a metal to flow through an electrolyte. In pipelines this can occur at insulating flanges or joints, because the current (electron) flow is interrupted by the insulating component. For all buried pipes the external buried soil environment can provide such a path but, typically, the soil resistivity and external coating creates a sufficiently large resistive path to limit any effect. However where there is a conductive fluid inside the pipeline it can provide an alternative lower resistance pathway (see Figure 2). For above ground pipes, the internal path is the only possible current route.

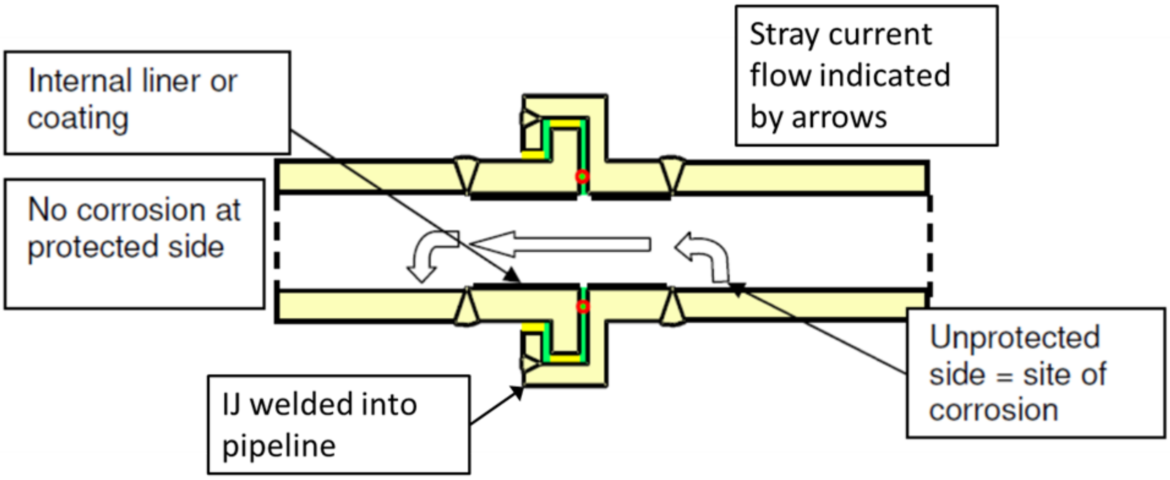

Figure 2. Stray current corrosion at an IJ

Experience has shown that even low dc current (typically as low as about 1 mA) is sufficient to cause a high rate of metal loss at localised points in typical pipelines, and affects both carbon steel and stainless steel pipelines.

3 Characteristics of attack

3.1 Point of Isolation

A characteristic of internal stray current corrosion is that the attack is located close to the point of electrical discontinuity (isolation) on the pipeline, but only on one side. Theoretically the highest rate of corrosion should be at the bare metal surface closest to the position of the isolation. However, if there are coatings or internal liners present, the site of corrosion may not be immediately at the point of isolation. It is also considered possible that if there is material inhomogeneity (e.g. a passive steel surface with disrupted oxide film or surface deposits), the site of corrosion may be a short distance from the joint or flange.

3.2 Driving voltage

Stray current will only flow from one side of the isolation (IF or IJ) to the other, if there is a driving voltage across the isolation. External cathodic protection (CP) can provide this voltage difference. Sections of pipelines are often isolated from a processing facility or similar, which have an extensive electrical earthing system, to prevent excessive current draining to the earthing system. In these situations, stray current corrosion is located on processing facility side of the joint, the unprotected side.

3.3 Electrolyte

There must be a conductive solution (i.e. one containing electrolyte) present to provide an alternative path for current flow. For an above ground pipe containing dry gas there is no electrolyte solution present. However, if the pipe is buried or if the pipe contains an aqueous phase, the surrounding earth or the internal aqueous phase can provide the path and stray current corrosion is a possibility.

The rate of stray current corrosion is dependent on the resistivity/conductivity of the electrolyte solution, the path length and the amount of solution present. For internal attack to occur, the presence of high levels of chloride would normally be expected to be present in the water phase, resulting in low resistivity (high conductivity), otherwise the resistance across a joint would be high and any current flow would be restricted.

3.4 Rate of attack

Internal stray current corrosion rates of attack can be very high, e.g. > 5 mm/year, much higher than other possible corrosion mechanisms.

4 Case A

4.1 Background

Failures of three different inter-field oil lines were reported by the operator, but in each case the failures had common features:

- The corrosion had initiated on the internal surface.
- The location of attack was next to an IJ or IF.
- CP had been applied to the pipeline and the IJ/IF was installed at the start/end of the pipeline to isolate the pipeline from the station infrastructure.
- The production fluid contained a water phase.
- The failure was located around the 6 o’clock position on the unprotected side of the IJ.

The corrosion and location of attack is shown in Figure 3 (arrowed). The internal picture shows the IJ in the foreground (orange painted surface), the circumferential weld and the corrosion attack in the pipe on the station side. The IJ is above ground and in the external view in Figure 3 it can be seen in painted red/brown. The CP was applied to the inter-field oil line (white coated pipe), which is to the right of the picture.

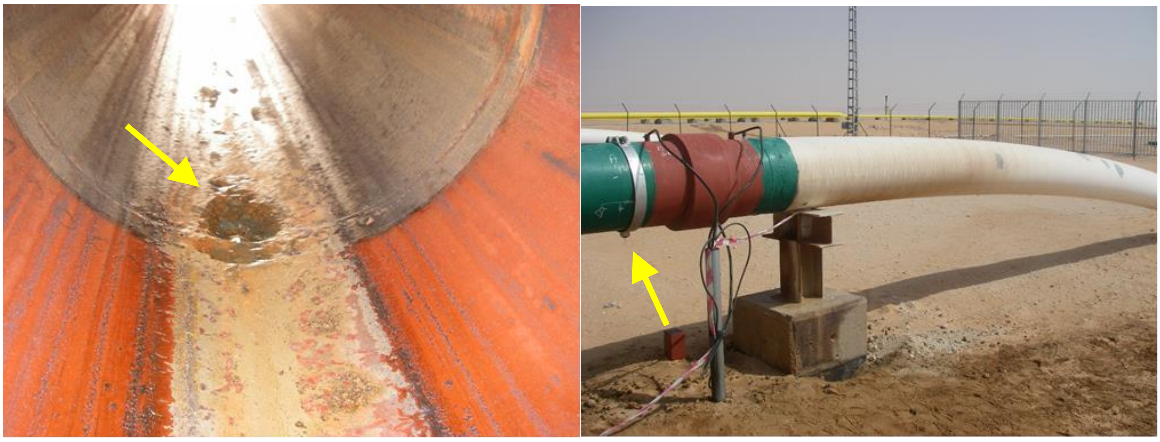

Figure 3 Location of corrosion at IJ

The oil lines had been protected from external corrosion by a protective coating in combination with impressed current CP. It was agreed by all parties that the likely cause of the failure was internal stray current. The failure was rapid with approximate wall thicknesses of 10 mm or more penetrated in 15 months. This rate of attack is beyond the normal range for corrosion in inhibited internal pipeline environments. Furthermore, the location of the corrosion at the unprotected side of the IJ and at the 6 o'clock position in the more dense water phase strongly indicated internal stray current was the mechanism of the failure. Therefore, the CP system was turned off, whilst preventative measures were considered.

A number of factors were considered to have contributed to the rapid failure:

- High conductivity of the water which provided a low resistance internal current path
- Proximity of the ICCP groundbed to the station which increased the likelihood of current flow to the station earthing
- The extensive station earthing system which included a bare steel water well casing which was an attractive path for stray current
- The presence of an anodic type inhibitor inside the pipe – the inhibitor could have concentrated the attack by acting as a partial coating. If present at sufficient level the inhibitor will prevent/minimise corrosion, however when the surface is polarised by several hundred millivolts or more the inhibitor will break down. It is likely that close to the IJ with internal stray current, the surface will be polarised by more than this limit.

4.2 Detecting internal stray current corrosion

Detecting the presence of internal stray current flow is not straightforward. Standard cathodic protection structure to electrolyte potential measurements, using a reference electrode in the external electrolyte can be used to determine whether an IJ is effective or not. If the same value is obtained on both sides then it is likely that there is a direct short. If different values are obtained either side of the IJ then it could be effective, but it could also indicate partial isolation, either a high resistance electrical connection or possibly an internal resistance through a conductive water phase.

Alternatively, resistance measurements (AC test current) can be performed, but for installed systems with sections buried in the ground, the value obtained will include the structure to earth resistance of each side, and hence a low resistance is not confirmation of a defective joint or an internal stray current issue. If the resistance to earth of the structures on both sides of the isolating joint is known, then the resistance of the isolating joint can be determined (Annex J in BS EN 13509:2003 [4]).

If the pipe is above ground or can be excavated, tests to check current flow through the isolating point can be undertaken by measurement of voltage drop in a known length of pipe (Annex K in BS EN 13509:2003 [3]).

An indication from data collected during commissioning as to whether an IJ or IF is not fully effective, is a reduction in the level of protection and corresponding change in the recorded pipe to soil potential values. See example data in Figure 4 which shows close interval potential survey (CIPS) data measured using a copper sulfate electrode (CSE) connected to the positive terminal. If the IJ/IF was fully tested prior to installation and found to be satisfactory and a change in potential values is seen approaching the isolation at 39 000 m, it could indicate current drain and the possibility of internal corrosion.

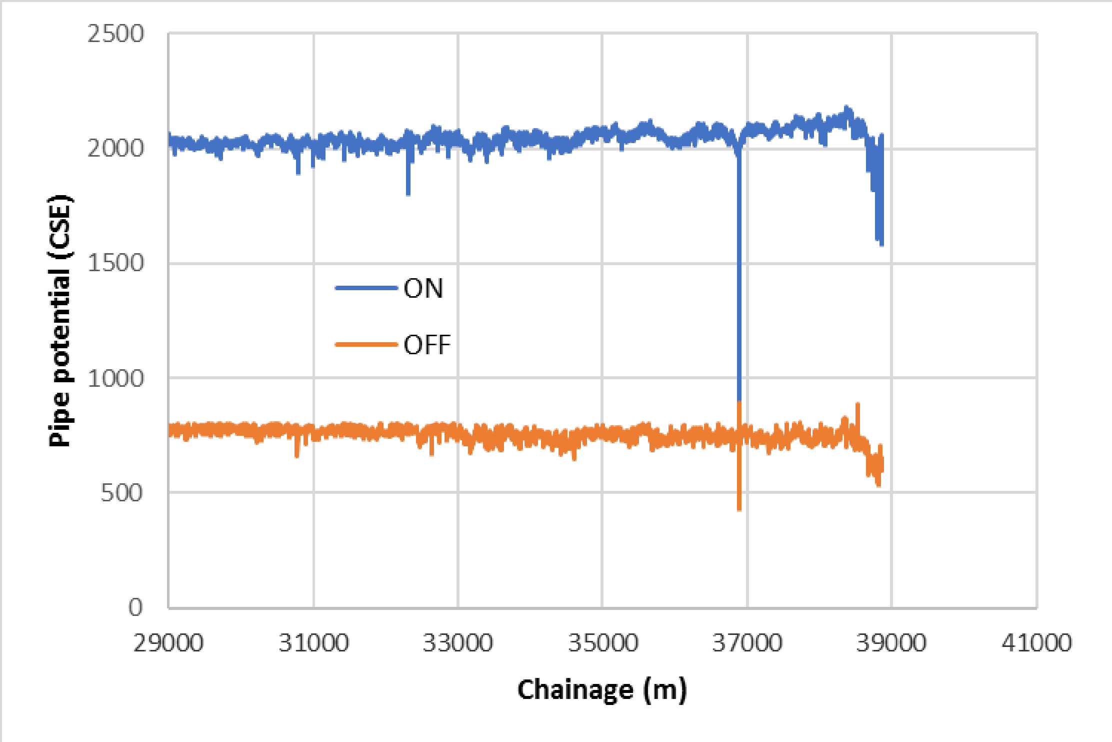

Figure 4 Close interval potential data (NB data collected by others)

4.3 Preventative measures

Removal of the water phase by introduction of water separation or improved efficiency of existing systems would be an effective solution, but in practice this is often not a practical nor cost effective option.

If the internal resistance between the two sections of pipe can be increased, by an internal coating or installation of a spool piece the rate of attack can be reduced. There are guidelines provided in the Shell Design & Engineering Practice document [5], which states that where the water phase resistivity is below 100 Ω cm or the water phase volume is above 5% of the pipeline volume, an isolating spool shall be used and the length determined by the following formula:

$$L = \frac{400 \times D}{\rho}$$

Where:

L = length of spool (cm)
ρ = water phase resistivity (Ω cm)
D = nominal pipe diameter (cm)

The above equation does not include driving voltage as an input, nor the cross-sectional area of the conductive (water) phase. Further calculations and equations to estimate the length of insulation are provided below in section describing Case B (section 5).

The length of spool predicted for various examples is shown in Table 1. For a 10” pipe the spool length required becomes impractical as the solution resistivity decreases. Smaller diameter pipes, such as 6” or 8”, require shorter spool lengths, but large diameter pipes, e.g. 20” require substantial lengths even for brine concentrations with resistivity around 20 Ω cm.

Table 1 Calculated spool lengths

Pipeline diameter		Water phase		Spool length
(Inch)	(cm)	Conductivity (mS/cm)	Resistivity (ohm cm)	(m)
10	25.4	50	20	5.08
10	25.4	2	100	1.02
10	25.4	200	5	20.32
8	20.32	50	20	4.06
6	15.24	50	20	3.05
20	50.8	50	20	10.16
20	50.8	200	5	40.64

In many stations the installation of an insulating spool piece of up to say 20 m in length is impractical due to space restrictions. There is also the issue of lost production which would be significant if a main oil line is shutdown specifically for a spool installation, unless the activity can be fitted into a planned shutdown period, or a bypass is available.

A third option to mitigate internal stray current is to bond across the IJ/IF. Of course, this is not desirable from a CP operation perspective, but may be preferable to regular pipeline failure. The main issue to be assessed is the level of current drain that is generated by the addition of the structures on the unprotected side of the isolation. Where there is an extensive electrical earthing system, the current drain is very likely to be considerably more than that required for the pipeline. Additional ICCP capacity might be needed, or measures to limit the current flow could be installed. The inclusion of a resistive bond across the IJ/IF could be considered. However, the selection of the resistance value is important, too high a resistance and appreciable stray current will simply continue to take the path through the electrolyte and cause corrosion.

A better approach to limiting the current, is to install if permitted, a dc de-coupler (cathodic isolator), which provides safe grounding for ac faults and lightning strikes, but blocks the flow of dc from the CP system. Installation of solid state units at key locations could significantly reduce the current drain.

5 Case B

5.1 Background

After only very short operating periods, failures of duplex stainless steels (DSS) flow and export lines were observed by company personnel at a number of stations. Cathodic protection had been applied to the export lines and the lines contained a water phase. At one location, immediately upstream of an IJ, a leak was observed at the weld (see Figure 5 and Figure 6). The section of trunk line was replaced, however, after 60 days in service the replaced section of pipe also failed. The wall thickness was 4.8 mm, giving a corrosion rate close to 30 mm/yr.

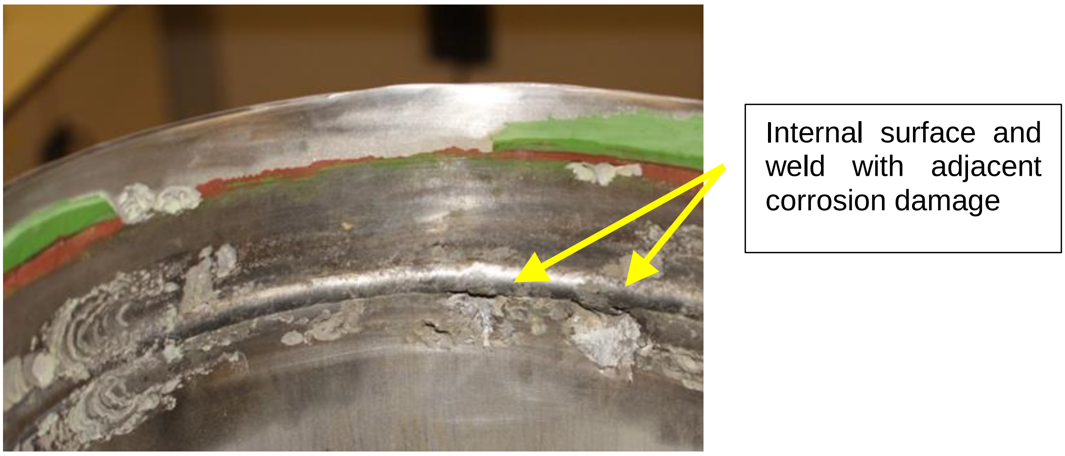

Figure 5 Location of leak

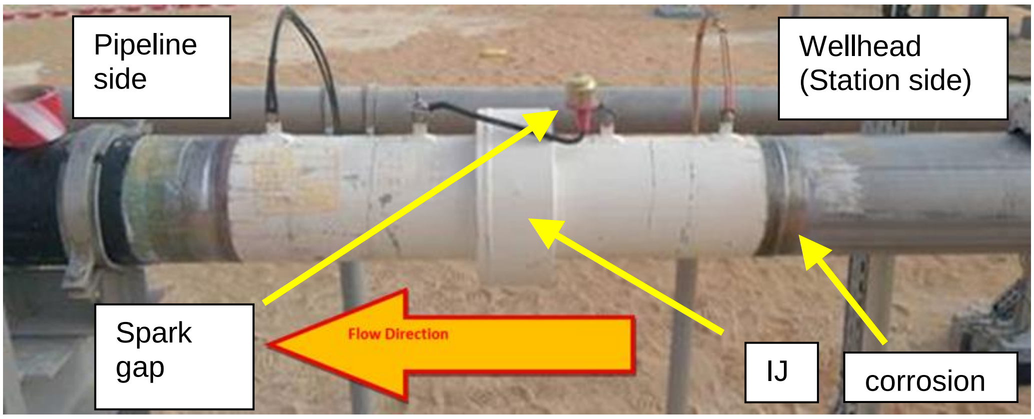

Figure 6. Failure at export line

Corrosion damage was also observed at IFs located at the wellhead (Figure 7). Cathodic protection was applied to the well casing via a vertical anode groundbed. The IF was installed close to the well head and was intended to restrict the CP to the wellhead and avoid current drain to the station electrical earthing system. The extent of the corrosion damage at the wellhead IF is shown in Figure 8.

Figure 7 Typical well head arrangement with IF

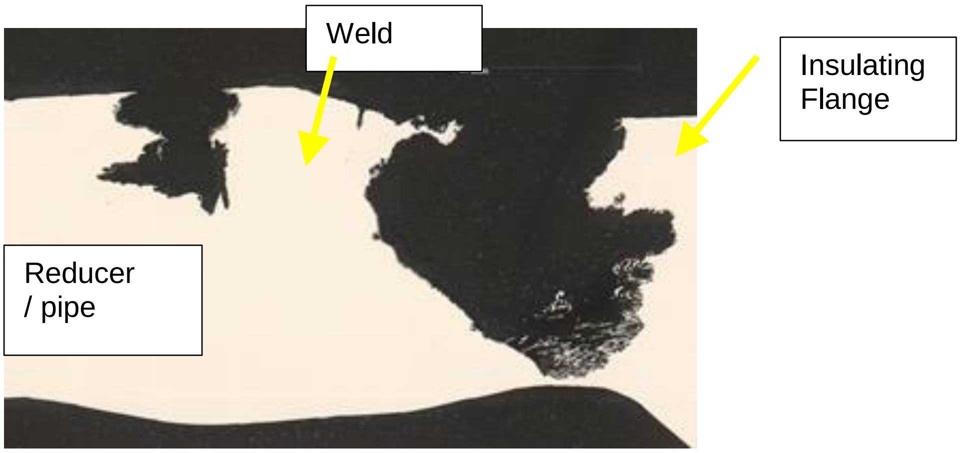

Figure 8 Cross section through a corroded weld area

As a result of the failure, phased array ultrasonic testing was performed at selected locations and severe wall loss was detected at several of the tested locations. On the basis that the attack was caused by stray current corrosion, all IFs / IJs at susceptible locations were bonded across. No further failures occurred after effective bonding had been installed.

5.2 Failure analysis

An investigation to confirm the root cause was undertaken and a number of corrosion mechanisms were considered. All the corrosion mechanisms considered required the presence of an ionically conductive medium in contact with the metal surface. The presence of a water phase was confirmed and high levels of chloride were measured in two samples collected from failed lines (40,000 and 45,000 mg/L). Based on the water volume production figures, the liquid contact area was estimated to correspond to approximately between the 5 to 7 o'clock positions.

A summary of the possible mechanisms is shown in Table 2.

Table 2 Possible internal production fluid corrosion mechanisms

Mechanism	Supporting Indication	Contradictory Indication
CO_2 corrosion	None.	• DSS is highly resistant to CO_2 corrosion to at least 200°C. • CO_2 corrosion rate of DSS would be very low. • CO_2 corrosion would be widespread not at specific isolated points.
Erosion corrosion (corrosion in high velocity or turbulent conditions)	Mechanism capable of causing observed rate of damage.	• Location of damage was not where expected (i.e. is not at areas of highest turbulence). • Morphology of damage was not consistent. • Superficial velocities very low (2-4 m/s).
Abrasion (mechanical damage by fast-moving solids)	Mechanism capable of causing observed rate of damage.	• Location of damage was not where expected (i.e. is not at areas of highest turbulence). • The undercut pitting was not consistent. • Superficial velocities were very low (2-4 m/s).
H_2S pitting	Visual appearance of H_2S pitting is broadly similar to that seen.	• H_2S content of gas was nil (<1 ppmv). • Only trace amount of sulphide was detected at three corroded areas. • Duplex is highly resistant to H_2S pitting.
MIC (by SRB)	Visual appearance of MIC during hydrotest is very similar to that seen.	• Only trace amount of sulphide was detected at three corroded areas. • MIC is rarely seen in flow conditions. • SRB not viable in produced fluid. • Contact time with hydrotest water may be sufficient to initiate MIC but insufficient to propagate to observed depth.
O_2 corrosion	Visual appearance of O_2 corrosion is very similar to that seen.	• O_2 corrosion is not capable of causing observed rate of damage.

The morphology of the attack was not necessarily typical of stray current corrosion, where the area of attack is often localised, open saucer-shaped pits, with smooth surfaces. However most, if not all, reports of stray current corrosion in the open literature are for carbon steel. The corrosion damage covered by this study mostly took the form of classic, undercut pits. Furthermore, the exact location of the corrosion is not typical of stray current corrosion in the cases of the IF, as the metal loss occurred some 130 mm remote from the insulating gasket.

In the absence of any credible alternative corrosion mechanism, and based on the fact that the remedial action of bonding across the isolation had proved effective it was concluded that the corrosion damage had been caused by internal stray current corrosion, as initially thought, with the cathodic protection system as the source of the current.

The stray current path that resulted in the damage at the wellhead IF is illustrated in Figure 9 and a nominal equivalent circuit is provided in Figure 10, which shows the major circuit resistances, including the stray current path. It is expected that the stray current circuit resistance values will be high in comparison to the CP circuit values, so that the stray current will only be a small fraction of the total current.

The electrical circuit is shown below:
① Current is injected into the ground from the anodes
② The majority of the current goes directly to the well
③ A small amount of current goes to the earth rods
④ The current passes through cables, earth straps and pipes , via the IF to the well

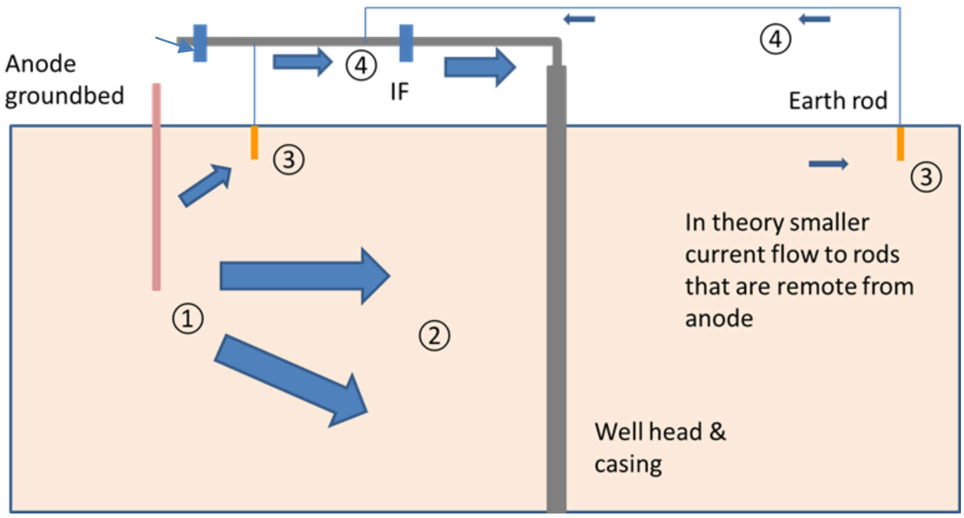

Figure 9. Stray current pickup on the earthing system

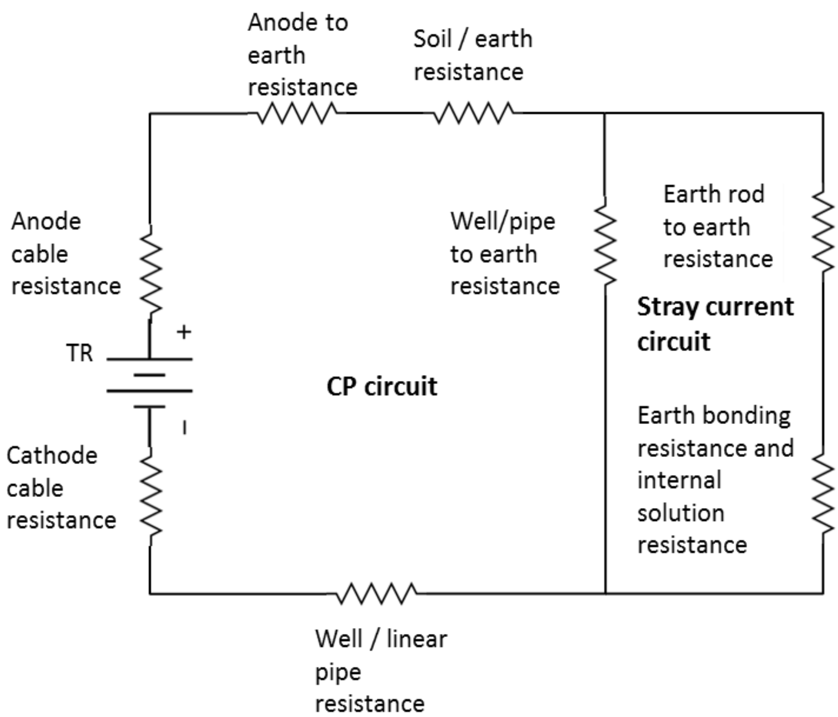

Figure 10. Nominal equivalent circuit including stray current path

Measurements on-site, with the IF bond in-place indicated that even when the well casing CP system was de-energised and disconnected there remained a current flow. This current was considered to be a galvanic current generated between the large surface area of the carbon steel well casing and the largely copper based electrical earthing system.

5.3 Preventative measures

The bonding across the insulating points was introduced as an interim measure to avoid further damage. Permanent stray current mitigation measures were considered and options are provided in Table 3. The most suitable option, or combination of options may differ site to site and will probably be influenced by practical and Health and Safety issues, and by financial constraints. The discussion below focuses on the corrosion at the wellhead IF location.

Table 3. Stray current mitigation

	Issue	Mitigation	Impact	Comment
1	CP system is source of stray current	Turn off all CP systems	Risk of corrosion to well casing and trunk lines.	• Not recommended in the long term.
2	Proximity of vertical ground bed and electrical earth system	Relocate ground bed or earth electrodes (100 m separation) and change to zinc	Reduction in the pickup of stray current	• Relocation of the copper electrodes would be the easier task. • Use of more active materials (e.g. zinc earth electrodes) may reduce interaction.
3	Stray current flow through earth system onto pipe	Install a DC blocker device [1]	Stray current flow would be eliminated	• The mitigation would only be successful if a single connection between the flowline and earth could be created (all other connections would need to be identified and removed or insulation provided). • If static build-up is an issue, a means of safe discharge would need to be devised.
4	Stray current flow through water phase at isolation	Remove all water content from production	All corrosion would be halted	• Very significant capital and operating costs
5		Insert isolating spool	Increase in internal solution resistance reduces stray current flow	• Calculations not considered accurate (see section below). • Length of required spool would increase if for example water content increased.
6		Increase turbulence of flow / install isolation in vertical orientation	Break up water phase, if non-continuous, path eliminated	• Not a technique known to have been tried before, consult with flow expert, undertake modelling.
7		Permanent bonds at all IF's and IJ's	Alternative safe path for current if low resistance	• Impact on performance of CP systems and galvanic interaction when CP systems are not operating need to be assessed.
8		Installation of 'sacrificial' spools to be replaced at predetermined intervals		• Use in conjunction with other mitigation – e.g. on a bi-annual basis

1 Also known as a DC decoupling device (see section 7.4.2 of BS EN 14505 [2]).

Use of Isolating spool

The use of an extended length of an isolating spool, as discussed for the first case, was again an option considered for the wellhead issue (Table 3 item 5). However, the practicality of this option depends on the length required.

An alternative to installation of an isolating spool is to internally coat the pipe on both sides of the flange as it increases the length and hence resistance of the water phase. However, particular care must be taken with the coating on the unprotected side as if a small area is left uncoated close to the IJ current discharge may be focussed at this point creating rapid metal loss. The liner/coating must reliably adhere to the metal surface, have excellent electrical resistance properties and not degrade (e.g. absorb water) in the product environment. The application of an internal coating, especially on small diameter pipelines, would require specialist input and application.

As for Case A the equation in [5] can be used to estimate the required spool length, however the water content in this case was reported to be significantly less than the 5%. Alternative calculations can be performed. Using typical electrolyte resistivity and water volumes, the resistance of the water phase across an IF/IJ can be estimated using the equation:

$$R = \frac{\rho \times L}{A}$$

where:

R = resistance (ohm)

ρ = electrolyte resistivity (Ω cm)

L = Length of coated / non metallic section (cm)

A = Cross sectional Area of aqueous layer (cm^2)

Aqueous phase resistance results for a range of pipeline diameters and water resistivity values are given in Table 4 for an aquous phase of 0.5%.

Table 4 Typical resistance across IJ (for pipeline with 0.5% aqueous phase)

Pipeline diameter		Aqueous phase		Length	Aqueous phase resistance
(Inch)	(cm)	Area (cm^2)	Resistivity (ohm cm)	(m)	(Ω)
10	25.4	2.53	20	1	791
10	25.4	2.53	20	5	3953
10	25.4	2.53	5	5	988
8	20.32	1.62	20	5	6173
6	15.24	0.91	20	5	10989
20	50.8	10.13	20	5	987
20	50.8	10.13	50	5	2468

For a 10” pipe IF with 1 m length of pipe internally coated (0.5 m each side) the internal solution resistance is approximately 790 Ω. By increasing the length of the coating the internal resistance is increased, which for a given driving voltage decreases the current flow and hence corrosion damage. For an internal coating length of 5 m (2.5 m either side) the resistance is close to 4000 Ω. Although this value might at first be considered as sufficiently high, if the driving voltage across the IF was 1 V, this would result in a current flow of 0.25 mA. Assuming that all the current flow is converted to mass loss of iron, a constant flow of 0.25 mA would be equivalent to an annual metal loss of 2.3 g or 0.3 cm^3. This represents a significant amount of metal loss for a typical pipe wall thickness of 10 mm, if concentrated in a small area.

The above calculation does not include the polarisation resistance between the pipe surface and water phase.

For DSS, if the internal potential at the point of current discharge remained in the passive potential range (at a potential more negative than the pitting potential) the anodic process would not be metal loss and the stray current flow could be tolerated without corrosion damage. However, if the surface potential exceeded the pitting potential, it would be expected that corrosion would be generated.

For smaller diameter pipes, as the water phase cross sectional area is lower, the resistance for a given length is higher (see Table 4). The opposite is true for large diameter pipes. The above calculations are based on a water phase up to 0.5%. If the water content was higher, and water content may increase with time, the amount of current transfer would increase.

Another equation, which includes driving voltage, has been utilised on water pipes [6]

$$L = 5 \times V \times \sqrt{\frac{r}{\rho \times Vcorr}}$$

where:

L	=	length of spool (m);
V	=	potential difference (V) assume 1 V
ρ	=	electrolyte resistivity (20 Ω.cm)
r	=	nominal pipe radius (12.7 cm)
Vcorr	=	acceptable corrosion rate (0.5 mm/yr to give a nominal 10 year life)

A detailed verification of this equation has not been undertaken, but using the above parameters for a 10” diameter pipe a length of 5.6 m is estimated. If a life greater than 10 years is required the length would need to be increased. As this equation is based on a water filled pipe, its application to the present situation is probably not appropriate.

A further expression is provided by Baeckmann et al [7]; here the length is dependent on the current density as follows.

$$L = \frac{\Delta V}{2}\sqrt{\frac{r}{\rho \cdot J_0 \cdot \beta}}$$

where:

J_0	Current density (A/m²) (taken as 0.5 A/m² = 50 µA/cm², equivalent to a corrosion rate of 0.5 mm/yr)
B	Tafel slop (V) (assumed to be 0.060 V)
ρ	resistivity (0.20 Ω m)
r	radius (0.127 m)

Hence again assuming 1 V driving voltage then the distance is 2.3 m. This value is lower than the previously calculated value, but of the same order.

In addition to calculations, modelling and testing using a large scale experimental model have been undertaken [8]. Hesjevik investigated the risk of stray current, including one 28" pipe with an aqueous phase. The voltage across the joint was estimated to be 0.4 V and the solution resistivity 198 ohm cm. Results of modelling indicated corrosion rates up to 1.2 mm/yr for aqueous depths of 100 mm, however for the specified operating conditions with only a thin aqueous layer the risk of stray current corrosion was considered low.

From the above calculations it can be seen that determination of the required length is not precise. Even when all the input parameters to the calculations are known, there is still uncertainty arising from the application of the equations which are probably derived for carbon steel in lines containing significant water phase, compared to this situation with duplex stainless steel.

Relocation of earth rods

In Table 3 modifications to the earth system are suggested as methods to mitigate the stray current corrosion, including relocation of the copper rod and a change from copper to zinc. The reason for the relocation is to increase separation distance between anode groundbed and thus make the rods a less attractive path for current. The change of material is suggested because copper has a noble potential and if placed in a voltage field where stray current can pick-up onto the surface, the current density will be high in comparison to zinc coated rods. As for CP design, if zinc electrodes or coated rods are used instead of copper the effective CP drain is reduced (see EN 14505, section 6.7 [2]). It is noted that the relocation and change to zinc may only reduce the current flow through the bond and not offer a complete solution.

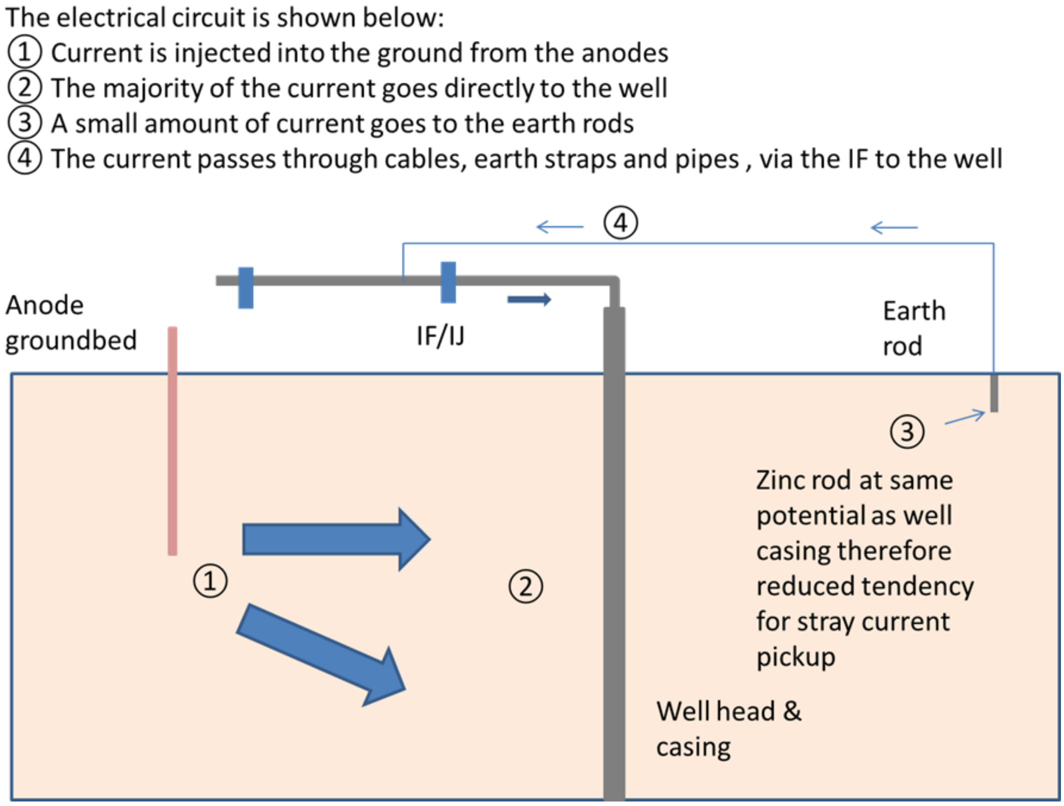

Figure 11. Minimising stray current at the wellhead IF by earth system modifications

6 Summary & Conclusions

Where internal stray current has occurred resulting in significant and repeated corrosion damage it is likely that the implementation of mitigation measures will be a complex activity. There is unlikely to be a single easy fix.

In the first instance, the safest and simplest approach is to install temporary bonds across the isolation, creating a 'blanket' CP system. This is an approach used for CP in complex and congested facilities and could be adopted as a permanent solution. However, it is necessary to check whether the existing CP systems can still work effectively. It is recognised that this is not an ideal solution, and other options such as relocation of groundbeds and installation of insulating spools should be considered for each individual case.

An accurate and reliable method of detecting stray current flow is required where mitigation measures are employed to allow the modifications to the system to be assessed, otherwise further failures could occur.

7 References

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