CP FOR CASED PIPELINES IN
SHORE CROSSINGS – CHALLENGES IN DESIGN

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SUMMARY: This paper presents an overview of cathodic protection (CP) validation techniques utilised in the project delivery of two recent cased pipeline installations at shore crossings in Australia. It discusses the complexities across changing electrolytes and details CP system calculations within casings. The practical limitations of existing CP monitoring equipment and the implications for the ongoing integrity management of pipelines within these installations are also discussed.

Keywords: Corrosion, Cathodic Protection, Electrolyte, Pipeline, Casing, Trenchless.

1.   INTRODUCTION

Pipeline easements are becoming increasingly restricted; traversing terrain where the only practical option is to install the pipeline through a casing. A casing can be either installed by auger boring, pipe thrusting, horizontal directional drilling (HDD) or micro-tunnelling. Where these casing arrangements are cathodically protected across boundaries of differing electrolytes, such as at shore (and river) crossings, the resistivity changes can be several orders of magnitude, meaning that the CP current density can also vary by several orders of magnitude. This could result in the pipeline being under protected in the higher resistivity environment and over protected in the lower resistivity environment.

The CP system is typically validated by independently assessing each side of the electrolytic boundary. The interface of these boundaries is not definitive and the interactions across the boundary complex and location dependent, however the validation methods described in this paper utilise this traditional bounded approach. In addition, various considerations for the monitoring of the CP system are presented and limitations with respect to typical offshore or onshore pipelines are discussed.
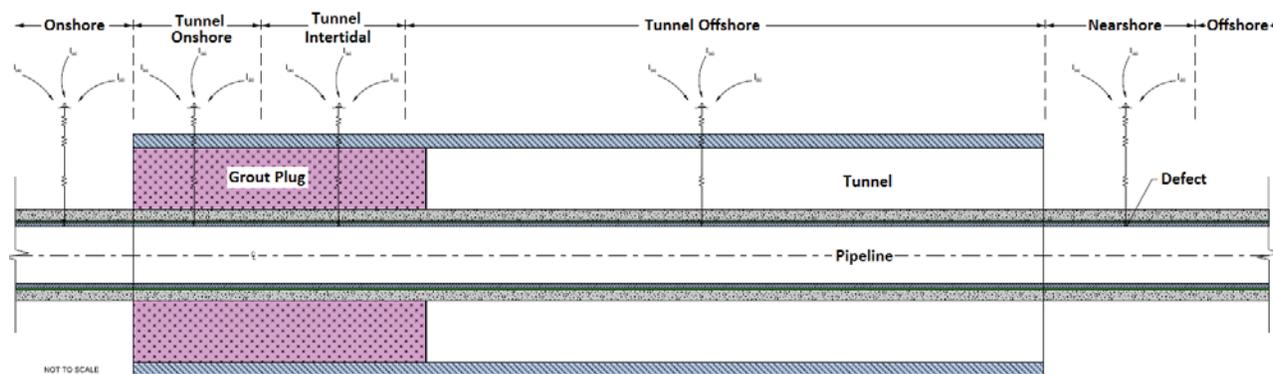

Figure 1 Cathodically protected cased pipeline across different electrolytes

2. OFFSHORE – SHORE APPROACH

Shore approaches of 'offshore' pipelines in Australia are usually protected from corrosion using an anti-corrosion coating supplemented by a series of galvanic anodes (bracelets) validated to the established methodology within DNV-RP-F103[1]. Shore approaches are typically trenched through the nearshore section with bracelet anodes attached to the buried pipeline. These bracelets are attached approximately every 300m upstream with an additional cluster of bracelets nearshore to account for the additional end-of-life current demand of a short section of the pipeline onshore.

2.1 Cased Shore Approaches

Where an offshore pipeline utilises a casing for installation across a shoreline, an assessment method is required to quantify the distance that sufficient cathodic current can traverse along the annular space from an external anode. Uncertainty remains in the industry as to how far into a casing sufficient CP current can propagate. DNV-RP-B401[2] and DNV-OS-J101 [2] indicates approximately five pipe diameters can be considered protected for mono-piles from an external system. This limit appears overconservative as CP current leeching through crevices onto a saline saturated pipeline surface is qualitatively accepted. For example, the ability for sufficient CP current to flow through crevices to exposed defects under loosely fitted high density polyethylene (or similar) field joint infill moulds (as shown in Figure 2) is often considered to be acceptable, even if not well quantified. It should be noted where these infill arrangements are pulled or pushed into high resistivity environments, an inherent escalation in the corrosion risk exists because sufficient CP current may not be reaching exposed surfaces.
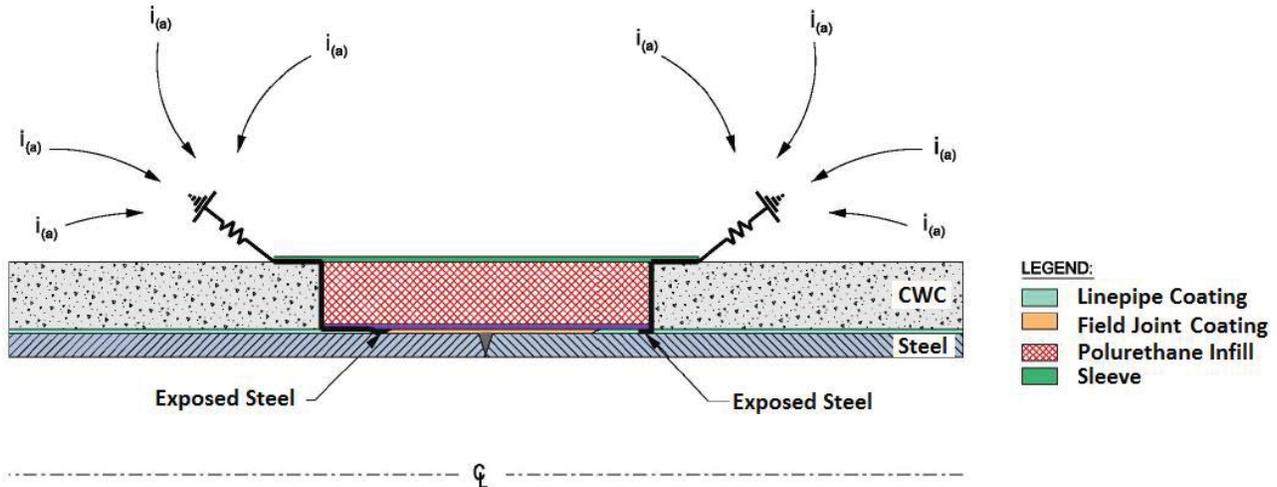

Figure 2 – Assumed propagation of CP current into field joint infill arrangements.

2.2 Theoretical Defect Assessment

For longer casings of 1km to 5km in length the engineer can assume they are outside any 'grey' limits of acceptable propagation distance. A relatively conservative assessment method has been developed to quantify if sufficient cathodic current can penetrate the casing wall rather than 'hoping' that sufficient cathodic current propagates along the casing annulus.

To determine if sufficient CP current will be available at the pipeline surface, an area of exposed steel, i.e. a theoretical coating defect, is assessed to confirm the driving potential required for connection to remote earth is within the CP system's capacity. If sufficient driving potential is available from the CP system, these defects can be considered protected through the casing from an external anode.

For this example the defect is modelled as a circular or disc electrode i.e. the point source formulae is utilised. Formulae for long slender electrodes may also be a reasonable assumption for a gouged coating. This assumption is for further discussion in the industry as the actual behaviour at the steel interface is much more complex, accounting for the steel surface polarisation resistance, shape and edge effects. The two examples discussed within this paper assess the code defined end of design life coating breakdown as a single theoretical circular defect rather than a combination of scattered defects and general coating degradation. This was considered suitably severe to dominate any of the previously mentioned effects.

Table 1. Coating Defect Assessment Key Parameters

Item	Parameter	Comment
a)	The strata resistivity external to the casing	This should be extracted from measured resistivity data.
b)	The casing resistivity	The casing resistivity should be assessed in an initial dry and operational saturated condition.
c)	The electrolyte resistivity within the casing annulus	The electrolyte resistivity changes are assessed.
d)	The required protective current density in the electrolyte	Protective current densities at start-up and end-of-life consider the oxygen content of the electrolyte in the annular space over time.
e)	The theoretical circular defect size	Back calculated per pipe joint as per DNV-RP-F103 coating breakdown per pipe joint [1].
f)	The driving potential of the CP system	Electro-potentials as documented in DNV-RP-F103.

[1] Actual current demand will be a complex function of coating degradation and scattered defects. For validation purposes, the circular defect assessment per pipe joint was deemed sufficiently conservative.

The calculation process is summarised below:

1. A theoretical circular defect is calculated from published coating breakdowns per pipe joint.

2. The current demand of the defect is calculated using the required protective current density for that environment.

3. The radius of a hemisphere that draws the same cathodic current as the theoretical defect area is determined.

4. The resistance to remote earth is calculated using the point current source field formulae.

5. Total voltage drop across the various strata is computed ensuring sufficient driving potential exists in the CP system.

The theoretical circular defect area is calculated from the final current demand per pipe joint over the protective current density for that section of the pipeline alignment as shown in Eqn (1):

$$A_d = \frac{I_p}{i_{cd}} \qquad (1)$$

Where:

A_d = Theoretical defect area (m^2)

I_p = Final current demand per pipe joint (mA)

i_{cd} = Protective current density for exposed submerged steel (Anaerobic) (mA/m^2)

The area of a hemisphere is calculated using the following Eqn (2):

$$A_h = 2\pi \times r_h^2 \qquad (2)$$

Where:

A_h = Area of a hemisphere (mm^2)

r_h = Hemispherical radius (m)

Substituting the A_d with A_h and transposing in terms of r_h results in:

$$r_h = \sqrt{\frac{I_p}{2\pi \times i_{cd}}}$$

The resistance to earth of the defect is calculated using the point current source field formula (3):

$$R_e = \frac{\rho}{2\pi \times r_h} \quad (3)$$

Where: $R_e =$ Resistance to Earth at a defect

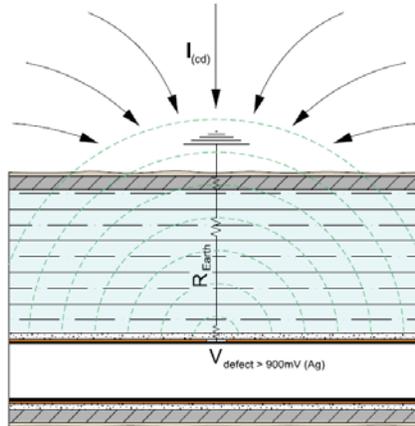 $\rho =$ Environment resistivity (Ωm)

Figure 3 – Defect Assessment

The total field to remote earth from the defect through the various layers of resistivity is calculated. If additional layers are encountered such as stabilisation grout, the potential across these layers can be accumulated into the total field to remote earth.

2.3 Example

An example is presented below:

A 42-inch pipeline installed within a seawater flooded concrete casing with ≈5% bare area (≈ bare field joint), can be assumed to draw 40mA with a protective current density of 20mA/m^2 (as per DNV-RP-F103[1] for pipelines in rock berms, considered reasonable given the tunnel's water fill is expected to have negligible oxygen replenishment) and a theoretical defect area calculated for pipeline and joint coating breakdown over 30 years. The casing, in this case a micro-tunnelled casing, is concrete with an internal diameter of Ø3.4m and wall thickness of 200mm.

Firstly, defect hemisphere radius and field to remote earth in the encasing electrolyte (A) is calculated as detailed:

- Theoretical defect area $A_d \approx 2$ m^2

- Equivalent hemispherical radius $r_{hd1} = 0.57$ m

Secondly, the geometric distance across each electrolyte boundary is calculated for respective potential drop to remote earth:

- r_{hd1} + the Annular Space in the Tunnel $r_{hd2} = 1.67$ m

- $r_{hd1} + r_{hd2}$ + casing thickness $r_{hd3} = 1.87$ m

The total potential field to remote earth is calculated using the following steps:

- Field to Remote Earth for the R_{hd1} in 0.3Ωm saline water $V(1) = 4$mV

- Field to Remote Earth for the R_{hd2} in 0.3Ωm saline water $V(2) = 2$mV

- Field to Remote Earth for the R_{hd2} in 100Ωm casing   V(3) = 383mV

- Field to Remote Earth for the R_{hd3} in 100Ωm casing   V(4) = 342mV

- Field to Remote Earth for the R_{hd3} in 50Ωm strata   V(5) = 171mV

- Driving Potential required between the pipeline and remote earth required for protection:

  V(1) – V(2) + V(3)-V(4)+ V(5) = 214mV

The sensitivity of the CP systems performance within each section of varying strata should be assessed. The most conservative section should be utilised for validation of the system. For instance, if the casing traverses strata of 500Ωm the additional driving potential required can be calculated as:

- Field to Remote Earth for the R_{hd3} in 500Ωm strata   V(5) = 1,710mV

- Driving Potential required between the pipeline and remote earth required for protection:

  V(1) – V(2) + V(3)-V(4)+ V(5) = 1,753mV

The driving potential of the galvanic system is limited to the electro-potential difference of the anode and the structure at the required protective potential. For pipeline design these figures are typically based on an alloy at -1,050mV (Ag) protective potential and protective pipeline potential of -800mV (Ag). Inherently we are left with 250mV of driving potential.

DNV-RP-F103 conservatively reduces this capacity for buried anodes. A nearshore design typically will have the pipeline buried to a sufficient depth to avoid exposure by wave action and seabed movement. The natural potential of the buried anode is assumed -1,000mV (Ag). If anaerobic protection levels are required, such as in stagnate anaerobic environments, -900mV (Ag) protective potentials are recommended. This implies only 100mV of driving potential remains in the CP system to drive cathodic current through the casing.

Using the defect assessment presented, an external galvanic system cannot be validated to the design standard as having the driving potential to penetrate a casing with sufficient cathodic current at the end of life as defined by DNV; therefore for validation of galvanic systems interfacing with cased installations, CP must be provided from within the casing annulus for the life of the pipeline.

However, external galvanic systems can be validated for temporary protection of cased installations. At start-up high casing resistivity may be anticipated prior to saturation of the casing, but with a high quality pipeline coating application, best practice transportation and a well-engineered installation, very low coating damage is anticipated. Therefore low current demand is anticipated at start-up. This low level of cathodic current may be provided from the low driving potential of galvanic systems.
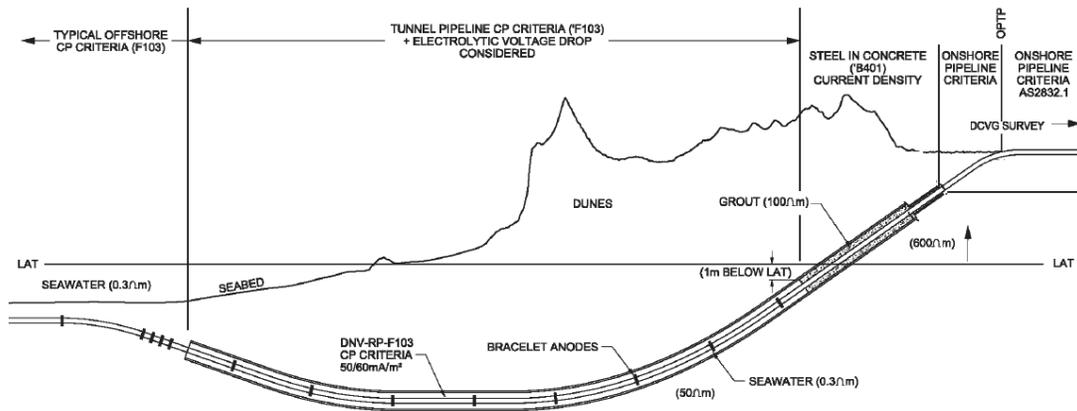

Figure 4 – Cased Shore Crossing Design

For validation of galvanic systems provided from within the casing annulus it is advisable to add additional conservatism and simplify the validation calculation within the casing. It is therefore assumed that the casing is completely shielding i.e. an anode cannot throw current to remote earth like when installed on an open seabed or a deeply buried condition. This implies an additional voltage drop through the dimensionally restricted annulus must be considered in the CP validation. This voltage drop is defined by the amount of annular space available around the pipeline as per Eqn (4) below. The position of the pipeline within the casing will create lower resistance path to the 12 o'clock position relative to the 6 o'clock position, this is considered negligible in the saline saturated environment and for the purposes of this paper is ignored.

$$E_{tot} = E_{Me} + E_{ann} \qquad (4)$$

$$E_{ann} = I_{cf} \times R_{ann}$$

Where:

E_{tot}	=	Total electrolytic voltage drop (V)
E_{Me}	=	Metallic voltage drop within the well coated pipeline (V)
E_{ann}	=	Annular space electrolytic voltage drop (V)
I_{cf}	=	final current demand (A)
R_{ann}	=	Casing annulus electrolytic resistance (Ω)

$$R_{ann} = \frac{L \times \rho_a}{\pi \times \left((R)^2 - (r)^2 \right)}$$

Where:

L	=	Pipeline length (m)
ρ_a	=	Resistivity of the seawater (Ωm)
R	=	Casing internal radius (m)
r	=	Pipeline outside radius (m)

For practical reasons the resulting arrangement is an abundance of anode mass within the casing, as the minimum anode spacing is dominated by the electrolytic voltage drop rather than attenuation. Additional redundancy should be installed to account for any electrochemical passivation or mechanical disconnection risks during installation, as inspection and mitigation is often not possible once installed.

2.4 Discussion

As detailed in the calculations above, galvanic systems have limited driving potential. As such, where a pipeline is installed within a casing underneath a long length of shore crossing or other waterway the ability of the galvanic system to protect sections of the pipeline upstream and downstream should be considered. As the bracelet anodes are within a casing rather than an open environment the resistance to earth of the anode system must be assessed through the various layers of strata.

Utilising a similar methodology to the layered strata assessment presented above, the anode can be assessed as to the driving potential to remote earth inside the casing. The capacity of the system to protect the upstream and downstream sections of the alignment can then be quantified.

Further considerations for any galvanic system which should be quantified during the design process are:

- The electrolytes composition over time and its effect on anode performance.

- Anode metallurgy and any passivation mechanisms.

- Anode electrical connection durability and installation method.

- Galvanic compatibility with any interfacing CP systems.

- The risk of leakage through or around upstream/ downstream Monolithic Isolation Joints (MIJs).

- Lightening and telluric current protection systems.

- Current drainage.

- Stray current pick-up from nearby infrastructure.

- Potential for damage to anodes during installation and ability to inspect and mitigate the damage.

- Design life extension requirements.

Where a galvanic system is deemed not acceptable in the design, an Impressed Current Cathodic Protection (ICCP) system may be an appropriate alternative. An ICCP system can have significantly higher driving potential then a galvanic system, thus cathodic current may be proven to penetrate the casing, although operator care is required so as not to overprotect the interfacing sections of the pipeline.

3. SHORE CROSSING - TRANSITION RISK

At any electrolytic boundary, such as from a submerged to dry pipeline environment in a shore crossing, it can be complex to predict the exact current flow of the CP system onto the pipeline. These transitions may have variable resistivity due to the wetting and drying effects of tides, groundwater movements or captured run-off. To add further complexity, the coating insulation resistance is likely to become variable across the electrolyte over time, often coating defects will not be evenly scattered, and exposed steel may have an uneven covering of calcareous film.

3.1 Offshore Anode Protection

Cathodic protection of the buried section of an onshore pipeline may be provided by the mass of the offshore CP system where current demand is suitably low and strata resistivity also suitably low. Typically onshore pipelines have significantly lower design average current densities due to the installation methods, buried environment, and accessibility for coating survey and coating repair.

A simplified schematic is provided in Figure 5 describing an electrical model of current flow for electrolytic transitions at shore crossings. For simplicity, the variability of coating performance is ignored and a new, well coated, properly installed pipeline is assessed without a casing.
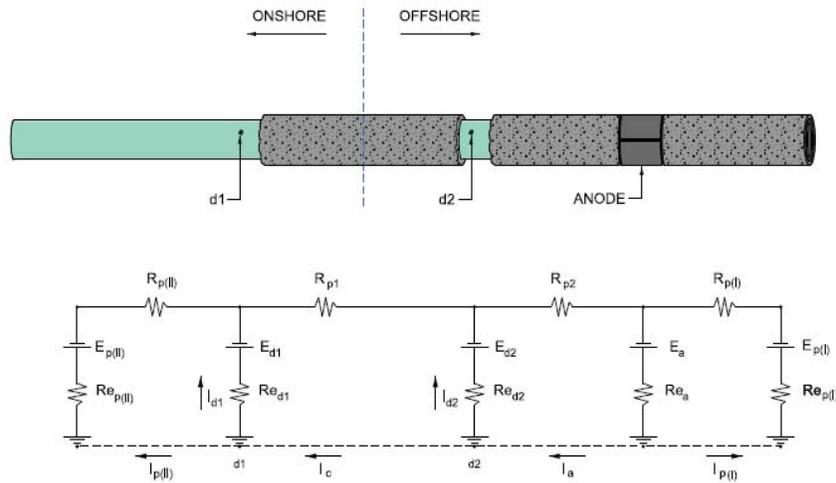
Figure 5 – Typical Shore Crossing Transition & Cathodic Protection

For a new, well coated pipeline, assume:

- $R_{p1} \approx R_{p2} \approx R_{p3} \approx R_{p(i)} \approx R_{p(ii)} \approx 0\ \Omega$

- E_{d1} = -550 mV Copper/Copper Sulphate reference electrode (Cu) for steel in compact type strata

- E_{d2} = -500 mV Silver/Silver Chloride reference electrode (Ag) for steel submerged in sediments

- Re_{d1} = Resistance to Earth of defect d1

- Re_{d2} = Resistance to Earth of defect d2

- E_a = -1.0 V(Ag) Al-Zn-In alloy buried in seawater sediments

- Re_a = Al-Zn-In alloy bracelet anode electrolytic resistance

In Figure 5 the two defect nodes, d1 and d2, are typically assumed protected by the mass of offshore anodes. The distance along the alignment which can be considered protected requires analysis of the transitioning ground resistivity and attenuation calculations.

The length of onshore pipeline that is protected can be estimated by attenuation calculations noting variable strata conditions require local assessment as per any onshore pipeline CP system design. Attenuation calculations alone assume an average current density along the pipeline and may not account for any significant defects or sections of high resistivity. Where the strata external to the pipeline is of high resistivity sufficient CP current may not be available at sections of exposed pipeline leaving the anti-corrosion coating as the only layer of defence against corrosion.

It is typically argued by operators that regular Direct Current Voltage Gradient (DCVG) surveys, albeit of lower resolution and confidence, can identify suspect sections of the pipeline alignment for exposure and repair. However, care should be taken as to the magnitude of the average current density utilised for the onshore transition as the pipeline may have been subject to increased coating damage due to the installation method. Additionally, the pipeline may lie at a depth beyond the resolution of a DCVG survey, or be practically prohibitive to expose for coating inspection or repair.

If DCVG is not practicable in these locations the corrosive risk to the pipeline should be further assessed in detail considering the corrosion risk of the strata.

3.2 Supplementary Onshore CP System

When considering a supplementary onshore CP system in combination with the offshore CP system for protection of the shore crossing transition, particular care is required as the onshore CP system is required to be electrically continuous with the offshore system. A differential in potential between the two different anodes (E_gb and E_a) may result in adverse current flows unbeknown to the engineer.
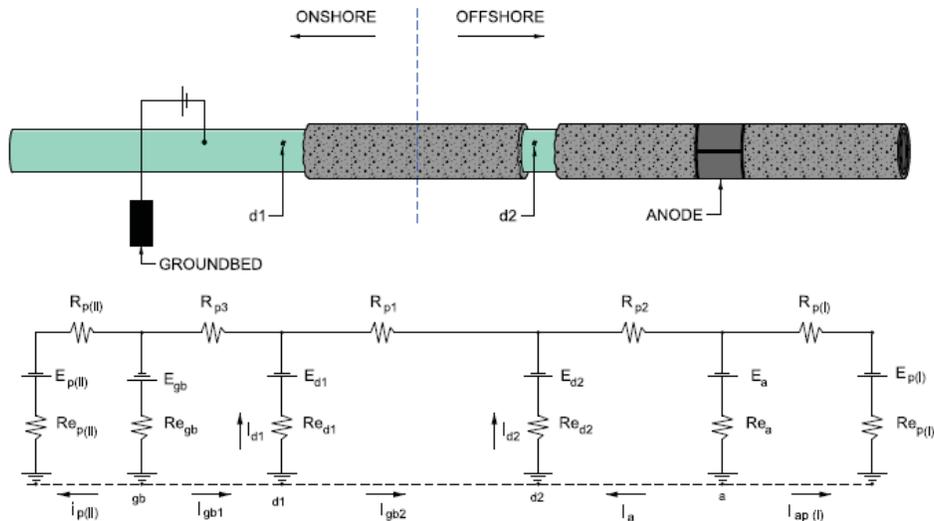

Figure 6 – Supplementary Onshore CP Systems (Mg Anode) at Shore Crossing

For the supplementary onshore CP system, assume:

- E_{gb} = -1.7 V(Cu) (High potential Mg anode)

- Re_{gb}, = Anode electrolytic resistance

Kirchoffs Current Law at defect nodes d1 and d2 defines the equations (1) & (2) below. The nominated current directions are assumptions and the solution will define the actual current direction within the circuit:

(1) $- (i_{d1}) + (i_{gb1}) - (i_{gb2})$ $= 0$

(2) $- (i_{d2}) + (i_{gb2}) + (i_a)$ $= 0$

From Kirchoffs Voltage Law for each anti-clockwise loop ensuring each voltage and nominated current direction concur:

(3) $- (E_{gb}) - (E_{Re\_gb}) - (E_{Re\_d1}) + (E_{d1}) - (E_{Rp\_3})$ $= 0$

(4) $- (E_{d1}) + (E_{Re\_d1}) - (E_{Re\_d2}) + (E_{d2}) - (E_{Rp\_1})$ $= 0$

(5) $- (E_{d2}) + (E_{Re\_d2}) + (E_{Re\_a}) + (E_a) + (E_{Rp\_2})$ $= 0$

By substituting Ohms law into (3) & (4) & (5), five equations are created with five unknowns, i.e. a solution can be reached.

The following worked example is given:

Assume:

- E_{gb} = -1700 mV(Cu) for a typical high potential magnesium anode in alluvial soil type strata.

- E_a = -1000 mV(Ag) for a typical Al-Zn-In alloy anode buried in seawater sediments

- E_{d1} = -550 mV(Cu) for steel in alluvial type strata

- E_{d2} = -500 mV(Ag) for steel in seawater sediments

- $E_{Rp\_1} = E_{Rp\_2} = E_{Rp\_3} = E_{Rp(i)} = E_{Rp(ii)} \approx 0$ V for a short length of well coated pipeline

- $E_{Re\_a} = i_{\_a} \times Re_{\_a}$, where the Al-Zn-In alloy bracelet anode electrolytic resistance is given by the following Eqn (5):

$$Re_a = 0.315 \times \frac{\rho}{\sqrt{A}} \qquad (5)$$

Where:

ρ	=	Environmental resistivity (Ωm)		= 1.5 Ωm
A	=	Exposed surface area of the anode for Ø44" (m²)		= 1.4 m²
$Re_{\_a}$	=	Bracelet anode electrolytic resistance (Ω)		= 0.4 Ω

- $E_{Re\_gb} = i_{\_gb} \times Re_{\_gb}$, where the Mg anode electrolytic resistance is given by the following Eqn (6):

$$Re_{gb} = \frac{\rho}{2 \times \pi \times L_a} \times \left(\ln(\frac{4 \times L_a}{\phi_a}) - 1 \right) \qquad (6)$$

Where:

ρ	=	Environmental resistivity (Ωm)		= 50 Ωm
L_a	=	Anode Length (m)		= 1.5 m
ϕ_a	=	Anode Diameter (m)		= 0.1 m
$Re_{\_gb}$	=	Slender anode electrolytic resistance (Ω)		= 16.5 Ω

- $E_{Re\_d1} = i_{\_d1} \times Re_{\_d1}$, and

- $E_{Re\_d2} = i_{\_d2} \times Re_{\_d2}$ where the defect polarisation resistance is given by the following Eqn (7):

$$Re_d = \frac{\rho}{2 \times \phi_d} + \frac{R_p}{A_d} \qquad (7)$$

Where:

ρ_{soil}	=	Environmental resistivity (Ωm)		= 30 Ωm
$\rho_{seawater}$	=	Environmental resistivity (Ωm)		= 0.3 Ωm
Ø$_{d1, d2}$	=	Defect diameter (m)		= 0.05 m
R_{p_1}	=	Polarisation Resistance[2] (Ω/m²)		$\approx$ 2.0 Ω/m²
R_{p_2}	=	Polarisation Resistance[2] (Ω/m²)		$\approx$ 0.5 Ω/m²
$A_{d1,d2}$	=	defect Area (m²)		= 2 × 10⁻³ m²
$Re_{\_d1}$	=	defect polarisation resistance (Ω)		$\approx$ 1,320 Ω
$Re_{\_d2}$	=	defect polarisation resistance (Ω)		$\approx$ 260 Ω

[2] Nominated polarisation resistance in soil is a typical value. For this example Rp in seawater (nearshore) is assumed to be 4 times lower than typical values used for steel in soil. Actual polarisation resistance at the steel surface in different environments is for further discussion and outside of the scope of this paper.

So substituting, we can calculate the magnitude and direction of the current terms in the worked example:

(3) $-(1.70) - (i_{gb1} \times 16.5) - (i_{d1} \times 1{,}320) + (-0.55) + (0) = 0$

(4) $-(0.55) + (i_{d1} \times 1{,}320) - (i_{d2} \times 260) + (-0.55) + (0) = 0$

(5) $-(0.55) + (i_{d2} \times 260) + (i_a \times 0.4) + (-1.05) + (0) = 0$

      a) i_{gb1} = 38.71 mA

      b) i_{d1} = 0.39 mA

      c) i_{d2} = 1.98 mA

      d) i_{gb2} = 38.32 mA

      e) i_a = -36.34 mA

Using Kirchoffs current law, i_a is actually negative to the direction assumed indicating that significant current from the higher potential Mg anode is being drawn to the bracelet anode. Although this model is only valid for this set of assumptions which have been selected to demonstrate the concern, this model indicates the current available to the onshore section of pipeline for cathodic protection may be significantly lower than the engineer intuitively assumes.

A supplementary CP system of similar potential may provide sufficient protection where the onshore pipeline has a very low resistance to earth such as a well installed, well coated pipeline in low resistivity soil, or an extremely well maintained coating on an operational pipeline. This effect should be validated in the field by critical assessment of measured data across a suitable sample of similar installations.

3.3 Casing Grout Plugs

Additional to the wetting and drying characteristics that are present at intertidal zone transitions and which are known to provide higher corrosion rates in steel pipelines [2 and 5], casings may further increase the corrosive atmosphere due to humidity and intermittent availability of any electrolytic medium due to air gaps resulting from tides or loss of annular fill. Where this condition is existent, this section of casing may be filled within a grout material (possible cementitous). This grouted section, or 'grout plug', should limit intertidal zone effects and ensure that a consistent conductive electrolyte, preferably of relatively high pH, encases the pipeline. The grout plug may also prevent the ingress of nutrients to reduce microbe induced corrosion (where water is used as annular fill) and other corrosive compounds carried in run-off during rain events or groundwater flow.

Validation for this section may follow the defect analysis methodology outlined above. As the surrounding environment is similar to 'steel in concrete', protective current densities consistent within the Cathodic Protection Design Standard DNV-RP-B401 and other available literature dependent on cementitous content, may be acceptable to the operator. The designer should also consider the interfaces of the grout plug, particularly at the saturated end of the grout plug, as some amount of capillary action is likely.

4. PIPELINE INTEGRITY MANAGEMENT CONSIDERATIONS

When designing a cased pipeline for a shore crossing the ability to inspect and monitor the performance of the CP system should be a key consideration, as coating tests are typically not practicable. For this reason, this section is considered higher risk than the onshore or offshore sections. Without access to the external surface of the pipeline, inspection methods may be restricted to internal pipeline inspection technologies; however consideration to ongoing CP monitoring should be included in the design. Local topography, landowner constraints, construction and operational limitations will often define the quantity and quality of data to be retrieved from cased sections of the alignment.

Dependent on the section length, pipeline diameter and casing diameter, a variety of options exist for monitoring of the pipelines CP levels. A dual monitoring system, such as through the use of coupons and reference electrodes, should be considered as a single source of input data may be problematic long-term. A dual system allows comparison of the collated data initially, and over time, to create a broad history of the system performance.

The engineer should also not ignore the developing field of Remotely Operated Vehicle (ROV) technology for inspection services and CP monitoring. A casing of reasonable diameter can be used to give access to launch the ROV and feed the trailing tether. The benefits during design life operation by allowing optical inspection and submerged pipeline potential measurement should be considered against the additional capital cost.

4.1 Permanent Monitoring Design

If there is no access to the external pipe surface and permanent reference electrodes or permanent resistance probes are to be installed, the permanent monitoring equipment design should take into consideration the warranted and/or expected life, cell passivation, cell contamination risks, and calibration requirements. The installation may be designed to allow the reference electrode(s) to be removed, or additional redundancy can be installed to ensure one reading has not drifted over time from a baseline measurement. Where a coupon based monitoring system is installed, coupon sizing and placement relative to the pipeline should be defined. Coupon sizing can be problematic in higher resistivity environments and specialist consultation should be sought for this otherwise theoretically simple monitoring system.

Where casings have a possibility to introduce current drain risks for the CP system over time, suitable connectivity should be installed at start-up to monitor any unwanted polarisation of the peripheral infrastructure.

The electrolyte within the casing annulus must be of low corrosivity and be non-damaging to the pipeline coating over the design life, including in regards to the pipeline's mechanical properties. An understanding of the electrolyte composition over time should also be captured. Where uncertainty remains electrolyte sampling infrastructure may also be considered in the design.
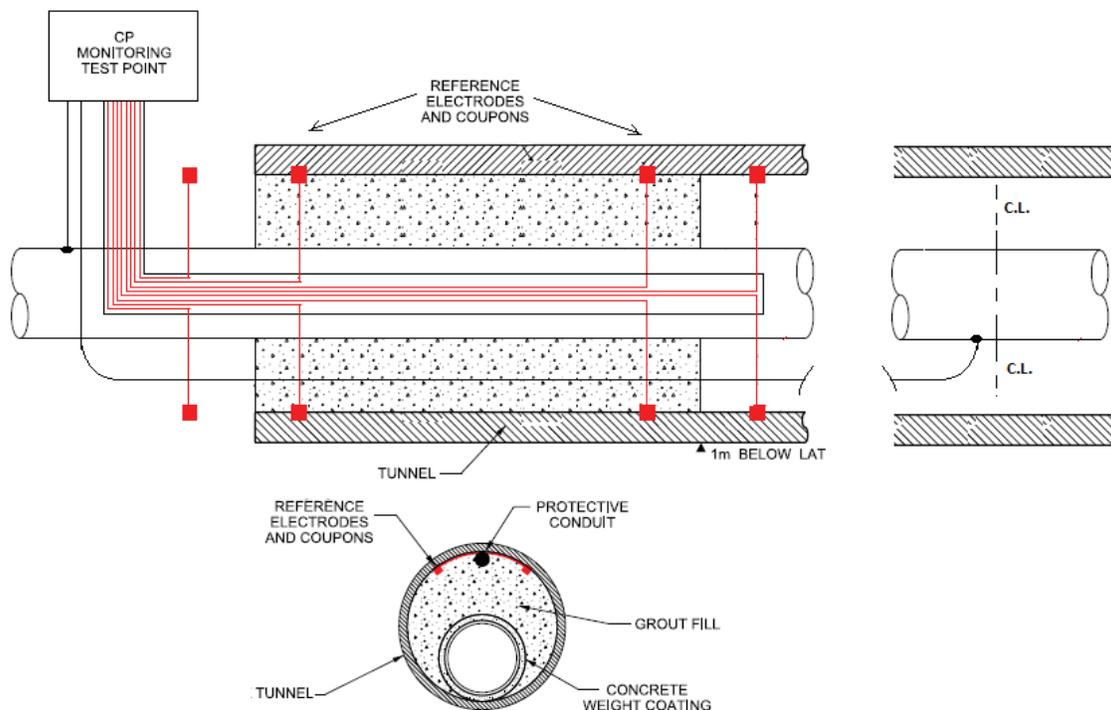

Figure 7 - Conceptual monitoring system through a non-metallic cased pipeline

5. CONCLUSION

Pipeline shore crossings involving a significant change in resistivity pose significant cathodic protection design challenges. This particularly applies to shore crossings that run between onshore and offshore where the resistivity changes can be several orders of magnitude. This means that the cathodic protection current density can vary by several orders of magnitude resulting in the pipeline being under-protected in the higher resistivity environment, and over-protected in the lower resistivity environment.

Attenuation has a significant effect on long crossings and at shoreline transitions. If bracelet anodes are used the resistance path along the casing annulus can be sufficient to render them ineffective. Additionally, if supplementary systems are proposed at the shoreline transitions, differentials in potential between two different anodes may result in adverse current flows.

There is limited guidance within existing codes specific for this installation type. As design criteria for the CP system are not defined, this paper has presented a simple modelling protocol that allows for the calculation of these affects so that cathodic protection design can be finely tuned to provide the optimum result.

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7. AUTHOR DETAILS

Marc Willis is a Lead Pipeline Engineer at Atteris. Marc has 15 years of industry experience including oil and gas onshore pipeline, facility design and CP. Marc has been responsible for the CP design of a number of recently installed micro-tunnelled casings which has formed the basis of this paper.
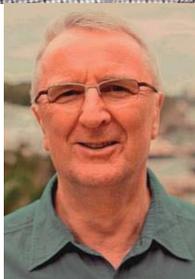
Brian Martin has been engaged in the corrosion control industry for over 40 years. His broad experience includes 26 years as a corrosion consulting engineer, 10 years as chief corrosion engineer for a pipeline operating company, 5 years as a chemist in heavy duty coatings, and 3years with a cathodic protection contracting company.
Brian has published 19 papers in refereed corrosion publications or the proceedings of refereed corrosion conferences, and presented 59 papers on corrosion protection.

Stefan Claveria is a Lead Pipeline Engineer at Atteris with over 11 years of industry experience in civil infrastructure and pipeline design both onshore and offshore. Stefan has been responsible for the delivery of a number of complex corrosion protection designs for pipelines and related infrastructure.