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AC Interference Corrosion, Corrosive Soil, Design Issues, Zinc Ribbon and Corrosion Mitigation

Mehrooz Zamanzadeh, Peyman Taheri, and George T. Bayer
Matergenics, Inc.
100 Business Center Drive
Pittsburgh, PA 15205

Julian Hristov and Kevin Groll
Matcor, Inc. by BrandSafway
1423 Wadsworth Street
Houston, TX 77015

ABSTRACT

A brief description of high voltage (HV) alternating current (AC) interference on buried coated pipelines is provided. Computer simulation for AC interference will be discussed. Relative ranking for: Separation distance, HVAC phase current, soil resistivity, co-location length and crossing angle will be provided and discussed. The case history portion of the paper includes an investigation that illustrated the problems inherent in AC mitigation with zinc ribbon in corrosive soils.

Keywords: AC Interference, Stray Current Corrosion, Corrosive Soils, Zinc Ribbon, AC Corrosion Mitigation

INTRODUCTION

There are two main reasons to be aware of induced AC on a pipeline: (1) Personnel safety and (2) Pipeline damage from AC interference.

Concerning personnel safety, AC interference on pipelines can cause harmful shock to pipeline technicians. The shock experienced will vary with the pipe-to-soil AC voltage at the time of contact, and the resistance between the body part in contact with metal and ground. Resistance to electrical current varies in the human body.[1] Externally, the resistance of dry skin is between 100,000 and 600,00 ohms, whereas the resistance of wet skin is 1,000 ohms. Internally, from hand to foot, the resistance is 400 to 600 ohms. From ear to ear, the resistance is 100 ohms. Resistance of the body to pipe and body to ground is influenced by the resistance of personal protective equipment (i.e. gloves and boots), and condition of the ground at the technician's feet (i.e. moisture content, resistivity, presence of dielectric barrier or presence of equipotential mat).

60-Hertz alternating current can cause harm at relatively low current levels.[1] At 1 milliamp or less there is no sensation. Painful shock begins at 8 milliamps, and 50 milliamps causes severe muscular contractions and breathing difficulties. Ventricular fibrillation can occur above 50 milliamps, and above 100 milliamps defibrillation may be required to restore normal heartbeat. Over 200 milliamps, severe burns and severe muscular contraction accompany ventricular defibrillation. In case of AC Interference, as current is induced on the pipeline, or in the event of a fault condition, a voltage gradient can occur around the above ground structures such that touching or even standing near these structures could result in electrical shock. The industry standard for AC mitigation on pipelines is to maintain voltage gradient (step-touch potential) below15 VAC.

Pipelines collocated in a right-of-way (ROW) with AC power lines, paralleling at a distance, or crossing power line ROWs may be subject to AC interference. Figure 1 is a photograph of aboveground natural gas pipelines co-located with electrical transmission lines. AC current induced on a pipeline may cause severe corrosion damage. Figures 2 through 4 are photographs showing the effects of stray current corrosion. Current from AC fault events may damage pipeline coatings, burn isolation devices or melt metal in extreme cases. Those tasked with maintaining pipelines require an in-depth understanding of the locations where pipelines are at risk of AC interference. Many factors are associated with increased AC interference and corrosion risk. These factors include: Soil resistivity, coating condition, cathodic protection levels, co-location length, crossing angle and separation distance. Traditional indirect assessment tools may be inadequate in identifying areas at risk for AC corrosion.

AC Interference

Electrical energy from an overhead or nearby power line can be transferred to a pipeline via three possible mechanisms. These mechanisms are electrostatic (capacitive) coupling, electromagnetic (inductive) coupling and conductive (resistive) coupling.

Electrostatic (Capacitive) Coupling

A capacitor is defined as two conductors separated by a dielectric material. In a capacitor, an electric field is set up between the two conductors, and the dielectric prevents flow of electrical current between the two conductors.

Pipeline sections strung out along a right-of-way and suspended by cribbing or sand bags, or individual pipe sections being lifted into a trench, can serve as capacitors. Under the proper conditions, electrostatic voltages can be generated on the pipeline sections. These static voltages can be large in magnitude but will only cause small currents when the pipe is contacted. The contact voltage may cause a person to become startled and this may result in a secondary safety incident. Electrostatic voltages are typically mitigated by earthing the pipeline and construction vehicles and using appropriate personal protective equipment during construction operations.

Electromagnetic (Inductive) Coupling

Electromagnetic inductive coupling occurs when a voltage is induced in a buried structure under the influence of the alternating electromagnetic field surrounding the overhead transmission line. The effect is similar to the coupling in a transformer, with the overhead transmission line acting as the primary transformer coil and the buried structure acting as the secondary coil. The magnitude of the induced voltage on the pipeline depends on factors such as the separation distance from the powerline, operating parameters of the powerline (voltage, current, phase, etc.), changes in the relative position of the pipeline to the powerlines (bends in the pipeline, change of powerline phase arrangements, etc.), and the coating quality.

Inductive coupling occurs during normal operating conditions and is the primary cause of AC corrosion. AC corrosion occurs where AC current flows between the pipe and soil at pipeline coating defects. Inductive coupling may also cause unsafe step-touch voltages on a pipeline. AC mitigation systems dissipate the induced voltages to safe levels and prevent AC current from transferring between the pipe and soil.

Conductive (Resistive) Coupling

Conductive coupling occurs when AC currents are directly transmitted to earth during transmission line faults. Usually such faults are of very short duration, but due to the high currents involved, substantial physical damage to coated pipelines is possible.

In electric utility transmission lines, fault or fault current is any abnormal operating condition that results in damage of equipment or disturbs the normal flow of electricity. A fault occurs when a path from conductor to ground is introduced such that the full current available in the circuit flows to ground. Faults may occur because of damage to AC components from lightning, high winds, failure/collapse of powerline structures or insulators, or accidental contacts between the powerline and other structures such as construction equipment.

Power transmission lines have the greatest risk of causing damage during to a pipeline from a fault event as these lines (as opposed to distribution power lines) operate at much higher voltages and have capacity to carry much higher currents. During fault conditions, voltages can drastically increase and can cause breakdown and melting of pipeline coatings. Fault events may also cause damage to the steel substrate of a pipeline. AC interference of 1,000 – 3,000 volts may cause coating damage. AC interference greater than 5,000 volts may cause pipe structural damage.

AC mitigation systems raise the voltage of the pipeline during fault events which eliminates harmful voltage gradients between the pipeline and earth. AC mitigation systems must be designed to protect personnel who may be in contact with the pipeline during fault events and must also protect isolation devices.

AC INTERFERENCE EVALUATION

Based on the lead author experience with AC corrosion related failures, we have developed the following guidelines:

1. AC induced corrosion does not occur at AC current densities less than 20 A/m^2; (~ 1.86 A/ft^2)
2. AC corrosion is unpredictable for AC current densities between 20 to 100 A/m^2; (~ 1.86 A/ft^2 to 9.3 A/ft^2)
3. AC corrosion will occur at AC current densities greater than 100 A/m^2; (~9.3 A/ft^2)
4. Highest corrosion rates occur at coating defects with surface areas between 1 and 3 cm^2 (0.16 in^2 to 0.47 in^2)

The following are standard AC interference evaluation and design steps that should be taken into consideration for existing lines.[2]

Step 1 – Assess whether there is a safe separation distance between the pipeline and AC structure(s). Evaluate whether mitigation measures are needed to protect the pipe. Recommendations should be made on options, such as rerouting a pipeline, to maintain a safe separation distance.

Step 2 – Calculate the voltage stress that would appear across the coating on the pipeline due to a powerline fault at a tower or powerline grounding system and refer to critical parameters to determine if remedial measures are required.

Step 3 – Conduct field measurements to detect stray current and or AC interference. Measure the soil resistivity at pipeline depth along the pipeline route, especially in areas of suspected low soil resistivity, so that the AC current density on a 1 cm^2 coupon can be calculated.

Step 4 – Estimate the induced voltage on the pipeline, using published figures and tables, for simple pipeline-to-powerline co-location arrangement. Mitigation is required if the steady-state step-touch voltage (Vg') is greater than 15 V at appurtenances based on the peak load current, and if AC current density (i_{ac}) is greater than 50 A/m^2 based on the average phase current loading.[2]

Step 5 – Install mitigation measures during construction in accordance with construction standards.

Step 6 – Install AC and DC coupons or corrosion rate probes at pipeline test stations and at locations of electromagnetic discontinuities so that actual AC and DC current densities and polarized potentials can be measured.

Step 7 – Install DC de-couplers across isolating joints and at bare steel casings in the piping system within 10 km of the pipeline-powerline co-location. Special consideration should be given to any detrimental effects that the transferred voltage or current could have on the structure being coupled to the interfered pipeline. Surge arrestors may be preferable to DC de-couplers in some circumstances.

Step 8 – Confirm adequate cathodic protection. Ensure that a minimum polarized potential of -850 mV_{CSE} is being met on the pipeline at test stations and locations of electrical discontinuities.

Step 9 – After construction and where possible, run a close interval survey to detect low cathodic protection levels and possible corrosion anomalies along the pipeline.

Step 10 – Use non-metallic enclosures and install dead-front terminal enclosures at cathodic protection test station locations to prevent incidental contact with an energized structure during fault conditions or when AC mitigation systems are disconnected.

Step 11 – Wherever possible make recommendations to pipeline company to run an in-line inspection tool through the pipeline section that is exposed to the AC interference to identify corrosion anomalies.

AC Interference Rankings

The following tables show the severity rankings for the factors that influence AC interference on a pipeline, which include: separation distance, soil resistivity, phase current, co-location length and crossing angle.[3] For the purposes of validating these severity rankings, software modeling was performed to validate and confirm each ranking.

Separation Distance

As the separation distance between a pipeline and HVAC line becomes closer, typically the AC interference risk will increase. The table below shows separation distances between a pipeline and a HVAC line and provides their severity rankings:

Table 1
Severity Ranking of Separation Distance[3]

Separation Distance – D (Meters)	Severity Ranking of HVAC Interference
D < 30.5	High
30.5 < D < 152.4	Medium
152.4 < D < 304.8	Low
304.8 < D < 762	Very Low

To verify the severity rankings for separation distance shown in the table above, a 30.5-centimeter (12-inch) pipeline with FBE type coating was modeled co-located with a parallel HVAC line for 1.6 kilometer (one mile). The transmission line modeled was a single circuit 3-phase transmission line energized with 500 amps of current in each conductor. Also, a uniform soil resistivity of 100 ohm-meters was modeled throughout the entire pipeline. Table 2 below shows the results of the calculated AC touch potential and AC current densities for the pipeline with the different separation distances applied.

The software modeling results validate the severity rankings shown in Table 1. Based on these results, a high AC interference can exist when the pipeline is less than 30.5 meters away from the transmission line when other contributing factors are present. The results indicate that as the separation distance increases, the AC interference on the pipeline decreases.

Table 2
Separation Distance Software Modeling Unmitigated Results

Separation Distance Type (Meters)	1.6-kilometer 30.5 cm (1-mile 12 in. pipeline) – Single Circuit Transmission Line (Parallel for entire length) – @ 500 amp loads & 100 Ohm-m uniform soil resistivity – Software modeling unmitigated results					
	AC Touch Potential (Volts)			AC Current Density (Amps / Meter^2)		
	Average	Max.	Min.	Average	Max.	Min.
15.2	4.59	9.14	0.00	10.36	20.62	0.01
30.5	3.75	7.47	0.002	8.47	16.86	0.01
76.2	1.95	3.88	0.00	4.40	8.76	0.00
228.6	0.73	1.46	0.00	1.64	3.29	0.00
457.2	0.36	0.73	0.00	0.82	1.64	0.00

HVAC Phase Current

When a HVAC lines' phase conductors carry AC current, an electromotive force (EMF) is induced on all nearby structures including buried pipelines. The higher the AC current on the phase conductors becomes, the more AC current is induced on the pipeline which increases the touch potential between the pipeline and remote earth. The table below shows the phase conductor currents on an HVAC line and provides the severity rankings for AC interference on a co-located pipeline:

Table 3
Relative Ranking of HVAC Phase Current[3]

HVAC Current – I (Amps)	Severity Ranking of HVAC Interference
I ≥ 1,000	Very High
500 < I < 1,000	High
250 < I < 500	Medium
100 < I < 250	Low
I < 100	Very Low

To validate the severity rankings for HVAC phase current shown in the table above, the same 1.6-kilometer (1-mile) pipeline was modeled. Table 4 below shows the results of the calculated AC touch potential and AC current densities for the pipeline with the different separation distances applied.

The software modeling results validate the severity rankings shown in Table 3. The calculated results indicate that the AC touch potentials and AC current densities on the pipeline will increase linearly as the phase current on the HVAC line increases and vice versa. The calculated values decrease by half as the phase current drops by half.

Table 4
HVAC Phase Current Software Modeling Unmitigated Results

Phase Current Type (Amps)	1.6-kilometer 30.5-cm (1-mile 12 in. pipeline) – Single Circuit Transmission Line (Parallel for entire length) –100 Ohm-m uniform soil resistivity – Software modeling unmitigated results					
	AC Touch Potential (Volts)			AC Current Density (Amps / Meter^2)		
	Average	Max.	Min.	Average	Max.	Min.
1,500	11.26	22.42	0.01	25.40	50.59	0.02
750	5.63	11.21	0.00	12.70	25.30	0.01
300	2.25	4.48	0.00	5.08	10.12	0.00
200	0.90	1.79	0.00	2.03	4.05	0.00
50	0.23	0.45	0.00	0.51	1.01	0.00

Soil Resistivity

Soil resistivity is one of the biggest influencing factors for AC corrosion on a pipeline. AC corrosion typically occurs faster in low soil resistivity soils such as clay or wet soils and slower in high soil resistivity soils such as sand or rocky soil. The table below shows the soil resistivity ranges and their severity rankings for AC corrosion:

Table 5
Relative Ranking of Soil Resistivity[3]

Soil Resistivity – ρ (Ohm-cm)	Severity Ranking of HVAC Corrosion
$\rho < 2{,}500$	Very High
$2{,}500 < \rho < 10{,}000$	High
$10{,}000 < \rho < 30{,}000$	Medium
$\rho > 30{,}000$	Low

Per the severity rankings table, a soil resistivity of less than 2,500 ohm-cm will cause a very high AC corrosion risk on a pipeline. Software modeling using the 1.6-kilometer (1-mile) pipeline model was performed to validate these rankings. Instead of the 100 ohm-m uniform soil resistivity model, each of the soil resistivities shown in the table above were studied as uniform models. Table 6 below shows the AC touch potential and AC current density results:

The results of the software modeling indicate the AC current density increases linearly and substantially as the soil resistivity at or near pipe depth decreases. Each time the soil resistivity decreased by half, the AC current density increased by almost half. Conversely, the AC touch potentials on the pipeline decrease minimally as the soil resistivity decreases. These results serve to validate the AC corrosion rankings shown in Table 5.

Table 6
Soil Resistivity Software Modeling Unmitigated Results

Soil Resistivity Type (Ohm-cm)	1-kilometer 30.5-cm (1-mile 12 in.) pipeline – Single Circuit Transmission Line (Parallel for entire length) @ 500 amp loads – Software modeling unmitigated results					
	AC Touch Potential (Volts)			AC Current Density (Amps / Meter^2)		
	Average	Max.	Min.	Average	Max.	Min.
2,000	3.55	7.07	0.00	40.07	79.82	0.03
5,000	3.63	7.24	0.00	16.40	32.69	0.01
20,000	3.82	7.61	0.00	4.31	8.58	0.00
40,000	3.89	7.74	0.00	2.20	4.37	0.00

Co-location Length

The length a pipeline is co-located and parallel with an HVAC line influences the AC interference risk. Generally, the longer a pipeline is parallel to an HVAC line, the higher the AC interference risk becomes. Table 7 below shows the co-location lengths ranges and their severity rankings.

Table 7
Relative Ranking of Co-location Length[3]

Co-location Length – L (Meters)	Relative Severity
L > 1524.0	High
304.8 < L < 1524.0	Medium
L < 304.8	Low

Per the table above, there can be a high AC interference risk when the pipeline is co-located with an HVAC line for more than 1500 meters. To verify the severity rankings for co-location length shown in the table above, the same 12-inch pipeline and transmission line were modeled with three different co-location lengths. The 100 ohm-m uniform soil resistivity model was applied. Table 8 below shows the results of the calculated AC touch potential and AC current densities for the pipeline based on the different lengths.

The results of the software modeling show that as the co-located length between the pipeline and HVAC line increases the AC touch potentials and AC current densities also increase and vice versa. These results confirm the severity rankings table for co-location length.

Table 8
Co-location Length Software Modeling Unmitigated Results

Co-location length Type (Meters)	30.5-cm (12 in.) pipeline – Single Circuit Transmission Line (Parallel for entire length) – @ 500 amp loads & 100 Ohm-m uniform soil resistivity – Software Modeling unmitigated results					
	AC Touch Potential (Volts)			AC Current Density (Amps / Meter^2)		
	Average	Max.	Min.	Average	Max.	Min.
3048.0	7.08	13.96	0.67	15.97	31.51	1.52
914.4	2.51	4.83	0.68	5.66	10.91	1.53
152.4	0.38	0.67	0.04	0.85	1.52	0.09

Crossing Angle

The crossing angle between the pipeline and HVAC line can also influence the AC interference risk. A pipeline does not have to be parallel or have a zero-degree angle to an HVAC line for AC interference to exist. Table 9 below shows the crossing angle ranges and their severity rankings:

Table 9
Relative Ranking of Crossing Angle[3]

Co-location/crossing angle– θ (°)	Relative Severity
$\theta < 30$	High
$30 < \theta < 60$	Medium
$\theta > 60$	Low

Software modeling using the 1.6-kilometer (1-mile) pipeline model was performed to validate these rankings. The 100 ohm-m uniform soil resistivity was modeled, and the HVAC line was modeled carrying 1,500 amps of current. The table below shows the calculated AC touch potential and AC current density results based on three different crossing angles.

Table 10
Crossing Angle Software Modeling Unmitigated Results

Crossing angle Type (Degrees)	1 mile 12 in. pipeline – Single Circuit Transmission Line– @ 1,500 amp loads & 100 Ohm-m uniform soil resistivity – Software Modeling unmitigated results					
	AC Touch Potential (Volts)			AC Current Density (Amps / Meter^2)		
	Average	Max.	Min.	Average	Max.	Min.
15	3.06	6.05	0.81	6.90	13.65	1.83
45	1.46	3.51	0.80	3.30	7.92	1.81
90	4.87E-07	9.52E-07	2.67E-08	1.10E-06	2.15E-06	6.03E-08

The results of the software modeling show that as the crossing angle between the pipeline and HVAC line decreases or is closer to parallel the AC touch potentials and AC current densities also increase and vice versa, as the crossing angle increases or becomes closer to perpendicular, the AC interference risk is low.

MITIGATION TECHNIQUES

AC mitigation techniques vary depending on level of AC interference to be mitigated, length of pipeline requiring mitigation, new or planned piping vs. existing piping, access for installation, operator-specific mitigation requirements and local soil/geology conditions. Once AC modeling and/or field studies are complete to identify locations requiring AC mitigation, mitigation techniques can be selected.

The most common AC mitigation technique is to install a linear-type conductor in parallel with the pipeline in areas that require mitigation. The conductor is commonly connected to the pipeline using a DC de-coupler. The de-coupler allows AC current to pass while blocking DC current. Linear installations can be designed to mitigate steady-state AC interference (i.e. inductive coupling) as well as protect against fault events (i.e. conductive coupling).

Two common types of linear conductors for AC mitigation are zinc ribbon and bare copper wire. The diameter, length and configuration (i.e. conductors on 1 side of the pipe or both sides of a pipe) will vary depending on the required resistance to earth needed for mitigation and the amount of current that the conductor(s) will need to carry. Additionally, special backfills may be used to lower the resistance of the conductor to earth. Common backfills include gypsum, bentonite, carbonaceous backfill and conductive cement.

When selecting the conductor and backfill for an AC mitigation system, the designer must consider the local soil conditions to determine:

1. What size (diameter, length, number) of conductor will satisfy the mitigation requirements?
2. Will selective backfill be required to meet structure-to-earth resistance requirements?
3. Will the conductor material and backfill be compatible with native soils and with each other?
4. Will the conductor experience either accelerated corrosion or passivation?
5. Can the conductor and backfill be installed by the allowable installation methods (e.g. installation in a shared trench during pipeline installation, cable plow, trenching, horizontal direction drill, etc.)?

The case study in this paper outlines a case when proper conductor material selection was not utilized for the given service environment. This led to premature failure of conductor and loss of AC mitigation.

Other methods that may be used in conjunction with or in lieu of linear-type mitigation are deep grounding wells and directly-connected sacrificial anodes. Deep grounding wells may be used to reduce pipe-to-earth resistance at peak AC locations identified by modeling or field testing. Grounding wells are sometimes used in lieu of linear materials when installation of linear conductors is impractical due to lack of land access, wetlands, neighboring utilities, etc. Grounding wells may be adequate to address inductive coupling but do not protect against fault events. Directly-connected sacrificial anodes are most useful to reduce local step-touch potentials at test stations and aboveground appurtenances. Operators must be aware of directly-connected anodes when testing cathodic protection and when searching for coating anomalies using indirect survey techniques. Anodes can affect CP results and can appear as coating anomalies.

CASE HISTORY OF ZINC RIBBON CORROSION IN AC MITIGATION

The client was experiencing corrosion of zinc ribbon used for AC mitigation of their buried natural gas transmission pipelines in the western United States. Corrosion of the zinc ribbon conductors had resulted in reduced AC mitigation. The authors were requested to assist in determining the cause of the corrosion problem.

Investigation

Comprehensive analyses of the corroded zinc ribbon and the soil in which it was buried were performed. Figures 5 and 6 present photographs of the corroded zinc ribbon. A review of the client's AC mitigation system for the specific area was performed.

Samples of corroded zinc ribbon, selected by the client from different locations, were analyzed by the following techniques: (1) Surface microscopy, (2) Cross-section metallurgical microscopy, (3) Scanning electron microscopy – energy dispersive x-ray spectrometry (SEM-EDS) for elemental analysis of corrosion products, and (4) X-ray diffraction (XRD) for quantitative crystalline phase analysis.

Soil samples corresponding to the locations of the corroded zinc ribbon samples were also provided for analysis. Soil analyses included: (1) pH, (2) as-received resistivity, (3) saturated resistivity, (4) chloride content, (5) sulfate content, (6) sulfide content, (7) carbonate content, and (8) Instantaneous corrosion rates of zinc, steel, and copper by linear polarization resistance (LPR). Table 11 presents the results of the soil analyses.

Table 11
Analysis of Soil Samples Corresponding to the Locations of the Corroded Zinc Ribbon Samples

Sample	Soil Resistivity (Ω-cm)		Instantaneous corrosion rate by LPR (mils per year)			Ion content				pH	Moisture content (%)
	As-received	Saturated	Zinc	Carbon steel C1010	Copper CDA110	Sulfate (ppm)	Chloride (ppm)	Sulfide (mg/L)	Carbonate (%)		
1	587	323	21.54	8.42	0.13	840	1206	<0.04	15	7.57	14
2	642	440	>40.00 (over range)	5.85	0.44	680	1078	0.07	12	7.58	15
3	225	133	22.97	7.93	0.71	2325	4836	0.05	12	7.62	13
4	187	137	12.14	5.09	0.32	6700	3360	<0.04	14	9.60	16

Surface microscopic analysis of all six zinc ribbon samples showed extensive corrosion products (white rust). Cross section microscopic analysis of all six samples showed typically brown inner layer and white outer layer corrosion products, or mixed corrosion products, ranging from 30 to 60 mils thick. Figure 7 is a cross sectional micrograph of the corroded zinc ribbon; with white corrosion product at the surface.

Scanning electron microscopy – energy dispersive x-ray spectrometry (SEM-EDS) and x-ray diffraction (XRD) analyses confirmed that the zinc corrosion products were rich in chlorine-containing and sulfur-containing compounds. This was expected given the soil chemistry. Water-soluble chloride compounds and water-soluble sulfate compounds can accelerate corrosion of zinc metal.

Discussion

All four soil samples exhibit low resistivity, high water-soluble chloride levels and high water-soluble sulfate levels. These factors all contribute to high corrosivity to zinc. LPR results and examination of the zinc ribbon confirmed these results.

It is also important to note that while the linear polarization resistance (LPR) corrosion rates of zinc in the four soil samples ranged from 12.14 to over 40.00 mils per year, the LPR corrosion rates of copper in the four soil samples ranged from 0.13 to 0.71 mils per year. A bare copper conductor would have been a better choice for use in these soils but may have also failed prematurely due to the corrosivity of the soils.

The design engineer should have considered life expectancy of different conductors in the native soils and use of selective backfills or alternative corrosion-resistant conductor materials to meet expected service life of the AC mitigation system.

Conclusion and Recommendations

The following soil corrosivity factors should be taken into consideration for designing an AC system in corrosive soils.[2]

- Soil resistivity
- Concentrations of chlorides, sulfates, carbonates and sulfides
- Moisture content
- Reducing or passivating nature of soil
- Soil pH

Conductor and backfill materials should be selected by a corrosion engineer to meet the life expectancy of the system. Corrosion rates for the conductor materials and risk of passivation (which creates risk of increased resistance between the conductor and earth) should be assessed.

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Figure 1: Photograph of aboveground natural gas pipelines co-located with electrical transmission lines.

Figure 2: Close-up photograph of AC stray current corrosion penetrating deep into the pipe wall.

Figure 3: Photograph of localized corrosion due to DC stray current. The appearance of DC stray current corrosion is similar to that AC stray current corrosion. Site testing is required to distinguish between AC or DC stray current corrosion damage.

Figure 4: Photograph of localized corrosion due to AC stray current.

Figure 5: Photograph of corroded zinc ribbon from corrosive soil in Western United States.

Figure 6: Photograph of corroded zinc ribbon from corrosive soil in Western United States – corrosion products removed for analysis.

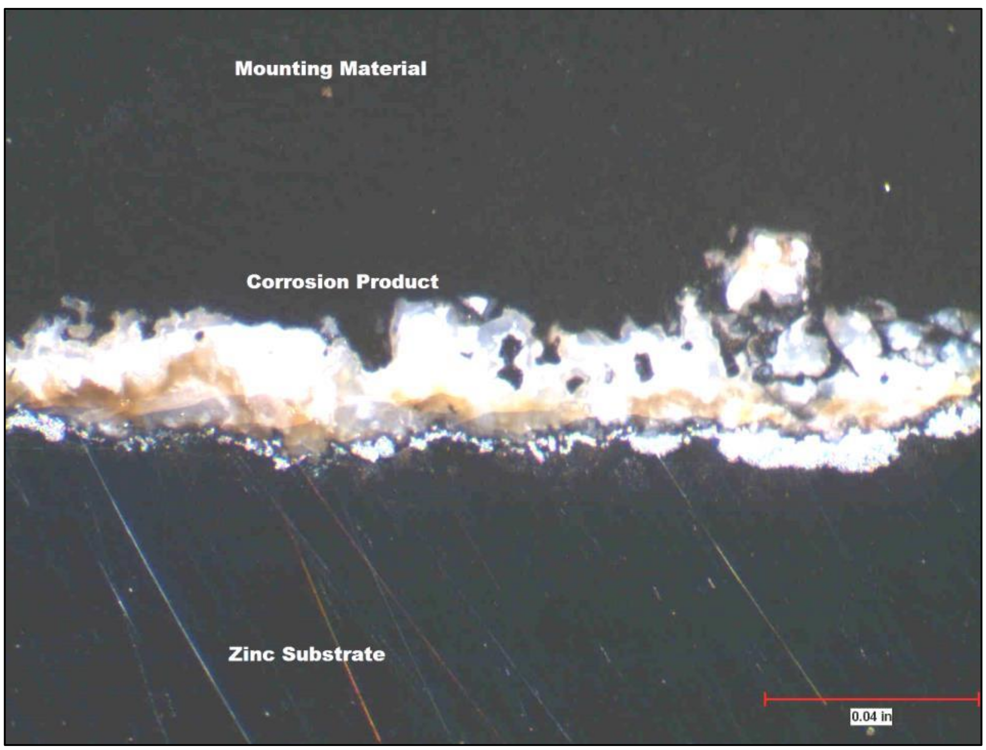

Figure 7: Cross sectional micrograph of corroded zinc ribbon with white corrosion product at the surface.

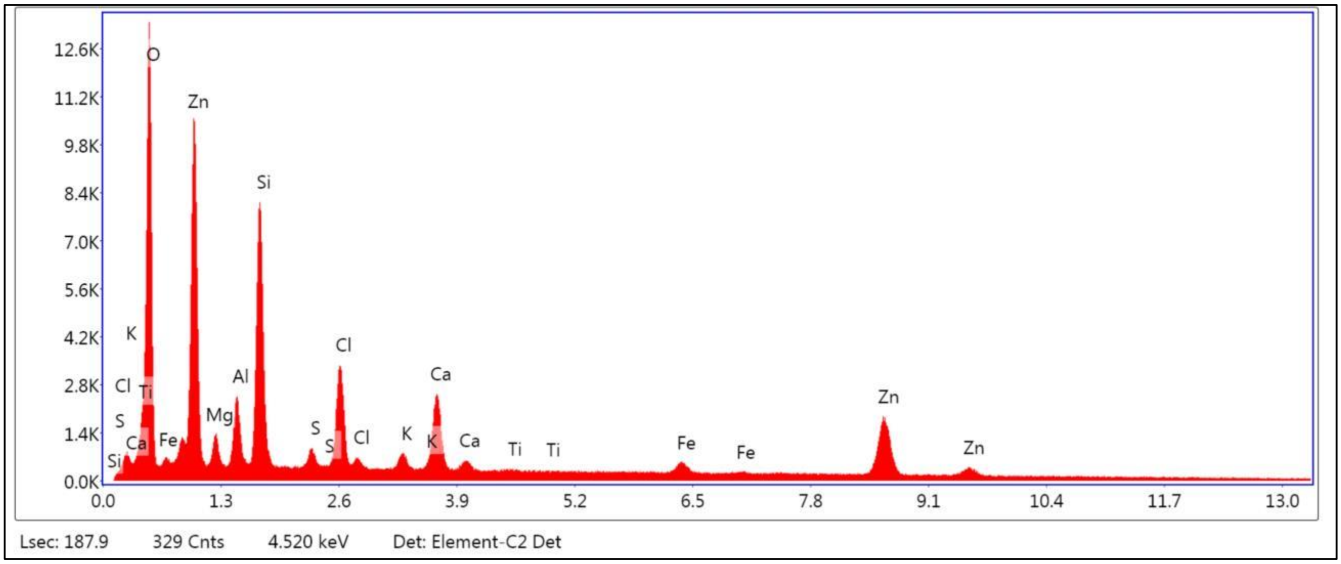

Figure 8: Energy dispersive x-ray spectrum of white corrosion product from corroded zinc ribbon. Results show pronounced chlorine (chloride) peak which is consistent with the high chloride content measured in the surrounding soil.