# A new equation proposed for evaluation of IR drop on buried pipelines

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**Abstract**

**Purpose** – In this investigation, attempts were made to distinguish critical coating faults in order of repair priority in DCVG + CIPS survey data by new proposed equation for calculating IR drop. The paper aims to discuss these issues.

**Design/methodology/approach** – DCVG + CIPS, XRD, EDS.

**Findings** – A new empirical equation was developed which is able to predict the importance more precisely. Besides, the studies proved the corrosion products were mainly hematite and goethite, and the presence of Cl anions was not noticed. As a result, the corrosion attack had a form of non-uniform localized corrosion.

**Originality/value** – The values were gathered by DCVG + CIPS method of survey.

**Keywords** Corrosion, Cathodic protection

**Paper type** Research paper

## 1. Introduction

There are several methods to distinguish and locate coating faults and corrosion areas on a pipeline. Inline inspection (ILI) tools and external corrosion direct assessment (ECDA) are the most widespread methods for this issue. ILI tools such as intelligent pigs involve inspection of pipe by magnetic flux leakage. ECDA involves surveying of pipelines by above-ground techniques and the analysis and interpretation of data is used in an attempt to predict the locations of metal loss sites. The concept is to locate, evaluate, predict, excavate, inspect and repair faults where metal lost through corrosion is most likely to have occurred. A potent and effective method of ECDA is direct current voltage gradient (DCVG) and close interval potential survey (CIPS) combined together (Taberkokt, 2006; Leeds and Leeds, 2006).

CIPS indicates the level of cathodic protection by measuring potential values during rectifier ON and instant OFF (IR free) states along a cathodically protected pipeline. It is well recognized that all form of CIPS do not detect small coating faults, which is fundamental limitation due to the lack of noticeable changes in potential. This method is effective for DC traction, telluric and long line currents that cannot be switched (Leeds and Leeds, 2004). DCVG involves determination of voltage gradient between two reference electrodes by application of a pulsed DC current. Combining the two methods can let the surveyor both measure the level of cathodic protection and also determine the presence of coating faults and their severity (NACE SP0169, 2007).

The analysis and interpretation of DCVG + CIPS survey data may allow critical coating faults to be ranked in order of their repair priority. The interpretation is based on calculated IR percentage, soil resistance, effective range of rectifier influence base on the location of anodic ground bed, and several other factors. Based on NACE Standard 0502 (NACE SP0502, 2008), the repair priority considering %IR values falls into four categories:

- *Category 1.* 1-15 percent IR: coatings fault in this category are of low importance.
- *Category 2.* 16-35 percent IR: coatings fault that are recommended for repair.
- *Category 3.* 36-60 percent IR: coating faults that are worthy of repair.
- *Category 4.* 61-100 percent IR: coating faults that are recommended for immediate repair.

However, the relevant percentage IR equation that is used for this issue, fails to predict accurately the repairing importance. The aim of the present study was to introduce a new formula for the prediction of repair priority in place of the relevant IR drop equation and to correlate results obtained from the new proposed equation with direct inspection findings after excavation.

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## 2. Methodology

DCVG + CIPS surveys were performed with a Cath-Tech Hexcorder (Millennium II Edition (DCVG + CIPS/GPS)) and its 200 A current interrupter model CI-200/GPS involving one surveyor. The procedure was implemented on the transition pipelines of 33 gas wells with total length of 150 km. This method involved measurement of the lateral voltage drop using two copper/copper sulfate half cells (one of the probes is always kept near the pipeline center line, while the other is held 1.5 m away perpendicular to the pipe) and the close order potential survey. The CIPS method employed measurement of the ON and OFF potentials of the pipeline while the protection current was interrupted by a current interrupter (Figure 1). The soil resistance was measured with a Unitest Cat. 8986 instrument using a four-pin soil resistance measurement method based on NACE TM 0102-2002 and ASTM G 72-1995.

The pipeline materials laid in the grade of API 5L-X42 with a typical composition of (wt%): 1.083 Mn, 0.120 C, 0.245 Si, 0.056 Cr, 0.06 V, 0.097 Cu, 0.04 Ni, 0.039 Mo, 0.01 P, 0.002 S, 0.027 Al, 0.03 Nb and balance Fe. Furthermore, energy dispersive spectroscopy (EDS) analyses were performed with an Oxford 7353 instrument having a resolution of 133 eV coupled to an SEM. X-ray diffraction (XRD) analyses were carried out employing a Philips PW 1840 with a Ni filter. The anode material was Cu with maximum power of 2.2 KW ($K\alpha_1 = 1.54056(\text{A}^\circ)$, $K\alpha_2 = 1.54439(\text{A}^\circ)$). Its spectra were analyzed by XPert Highsore 1.0d software.

## 3. Results

Soil resistance ($\Omega \cdot$ cm) was measured along the pipelines in the survey path. The result showed that the soil was moderately corrosive and had the same character along the pipelines (Table I).

The transfer pipelines conveyed the sour gas from their relevant wells to central measuring facilities for further processing. Afterwards, the gas was dispatched to refinery facilities and refined to sweet gas. All of the pipelines were built of 12 meter 8″ seamless pipe coated with coal tar enamel and had been on average more than 25 years in service. Among the tested pipelines, AL65 and AL99A showed sharp and high voltage gradient (HVG) in their survey data. In addition, they demanded higher-than-normal CP currents relative to their length. DCVG + CIPS diagrams of the AL65 pipeline (Figure 2) showed two distinctive HVG regions (HVG regions are the regions where the difference in voltage gradient ($\Delta G = G_{ON} - G_{OFF}$) gradually increases from a low value to a maximum value followed then by a decrease to a lower value again). In consequence, a peak is detectable in the voltage gradient diagram. These results include chainage (measured distance in meters form the start point) 0 + 039.6 to 0 + 064.7 m (Figure 3) and 0 + 169.5 to 0 + 184.3 m with total lengths of 25 m and 15 m, respectively. Direct inspection followed by excavation of these regions proved that the main coating faults were disbonded coatings with severe corrosion and voluminous oxides all around the pipelines under the disbondedments (Figure 3). In order to reach bonded coatings to pipe metal, the first HVG region was extended to 62 m. Three pipes with a length of 12 m (36 m) were replaced, due to extent of corrosion, and the entire length of 65 m was recoated. The second HVG region was extended to 37 m and one pipe (12 m) was changed. The whole repair length was recoated. Figure 4 shows the DCVG + CIPS diagrams of AL99A that had a unique HVG region from chainage 0 + 054.6 to 0 + 065.4 m. Similarly, direct inspection after excavation confirmed that the main coating faults were disbonded coatings and voluminous oxides were observed around the pipes (Figure 5). In a same manner, the HVG region was extended to 53 m to reach satisfactorily bonded coating. 17.4 m of the pipes were replaced and the whole repair length was recoated.

## 4. Discussion

### 4.1 Proposed new equation

On a coated pipeline that is cathodically protected, CP current flows from the anodes of the ground bed through the soil and to the coating faults. The voltage developed between two points on the surface of the ground, obeys Ohms law (V = IR) where V is the voltage gradient (volts), I is the current that flows to the coating defect or holidays (ampere) and R is the resistance ($\Omega$) resultant from soil the resistance, coating resistance, contact resistance, etc. (Nicholson, 2008).

Conventionally, holiday or defect severity is evaluated by estimating a "percentage of IR" value. This is calculated base on the following formula:

$$IR\% = \frac{\Delta G}{\Delta V} \times 100 \tag{1}$$

**Figure 1** Survey method of DCVG + CIPS

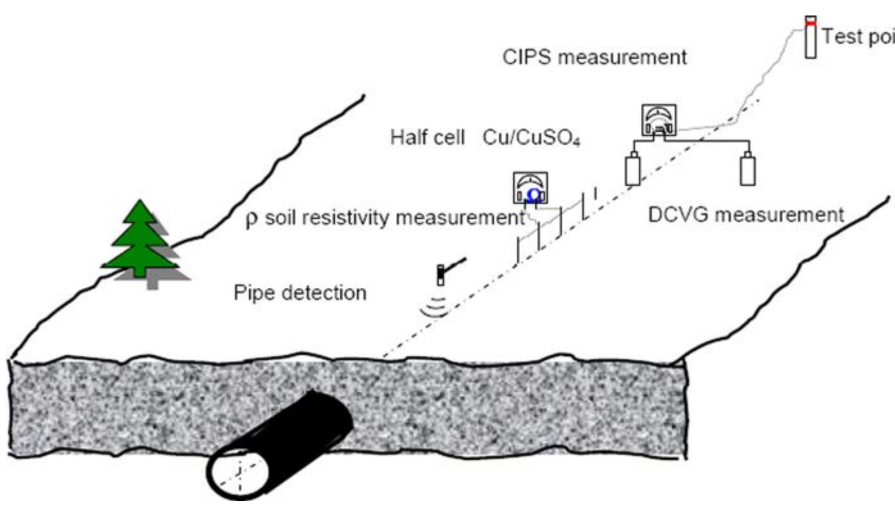


**Table I** Soil resistance at the vicinity of AL65 and AL99A pipelines

| Pipeline | Depth to end of layer (m) | Layer resistance (Ω · cm) |
|---|---|---|
| **AL 65** | 1.5 | 1,400 |
| | 3 | 1,000 |
| **AL 99A** | 1.5 | 1,400 |
| | 3 | 1,000 |

where ΔV is the difference between the ON and OFF potential of the pipeline ($\Delta V = V_{ON} - V_{OFF}$ (mV)) and ΔG is the difference between ON voltage gradient and OFF voltage gradient ($\Delta G = G_{ON} - G_{OFF}$ (mV)). The $G_{ON}$ voltage gradient (mV) is the result of difference between ON recorded potentials of two copper/copper sulfate half cells moving over the pipeline and the $G_{OFF}$ voltage gradient (mV) is the outcome of subtraction of the OFF values of these moving probes. These values are free from IR drops that are resultant primarily from holidays and coating faults or failures of other types. In general, the larger ΔG relates to larger coating defects (Taberkokt, 2006; Nicholson, 2007).

%IR calculated for HVG regions of AL65 and AL99A, based on equation (1), showed that these regions belonged to the first category of repair priority, which recommends there is no need for repair activities (Tables II-IV). Direct inspection after excavation of HVG region proved that the percentage IR calculated from equation (1) failed to predict correctly the order of repair priority of critical coating faults. Figures 3 and 5 show the extent of metal loss and the need for imminent and immediate repair. Consequently, a new empirical equation was proposed to calculate percentage IR drop and compensate for the lack of reliable repair priority prediction:

$$IR\% = \frac{\Delta(\Delta G)}{\Delta P} \times 100 \tag{2}$$

$\Delta(\Delta G) = \Delta G_{\max} - \Delta G_{\min}$ (mV) is the difference between maximum and minimum ΔG in the HVG region. ΔP (mV) is the difference between related ON potential values of maximum and minimum ΔG, in the mentioned region.

*4.1.1 IR drop of AL65 pipeline (first HVG region)*

The calculated percentage IR result based on equation (1) is shown in Table II. The maximum percentage of IR values fall into the first category (1-15 percent), which indicates that the coating faults were of low importance. However, as mentioned previouly, direct inspection after excavation revealed disbonded coating with severe and voluminous corrosion products required immediate and extreme repair action and the need for pipeline replacement. Due to lack of reliable prediction of the repair priority, IR percentage drop values were calculated using equation (2).

Δ(ΔG) is estimated between the maximum and minimum ΔG, chainage 0 + 047.4 and 0 + 039.5, respectively:

$$\Delta(\Delta G) = \Delta G_{0+047.4} - \Delta G_{0+039.5} = 38.8 - 0.7 = 38.1 \text{ mV} \tag{3}$$

$$\Delta P = V_{ON_{0+039.5}} - V_{ON_{0+047.4}} = 1473 - 1423 = 50 \text{ mV} \tag{4}$$

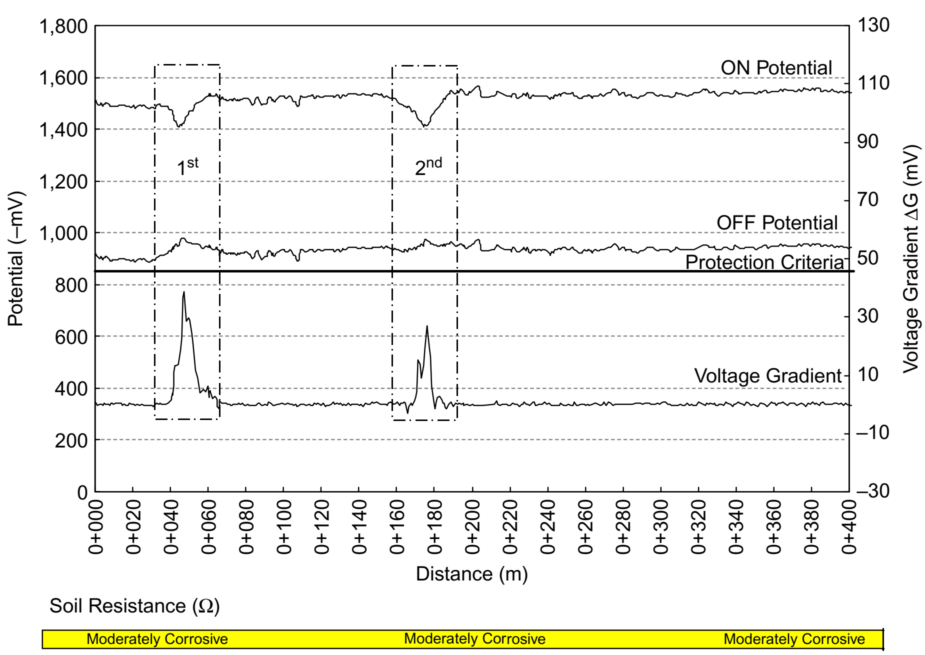
$$IR\% = \frac{38.1}{50} \times 100 = 76.2 \tag{5}$$

It is now clear that the calculated value should belong in the fourth category of %IR, which emphasizes the necessity of repairing the pipeline at the earliest convenience.

*4.1.2 IR drop of AL65 pipeline (second HVG region)*

Table III shows the recorded potentials in the second HVG region. As can be noticed, the maximum IR drop value calculated from equation (1) was 6.1 in this region, requiring no action for repairing. However, line excavation followed by direct inspection showed that severe corrosion had occurred under disbonded coating areas, emphasizing not only that coating repair was required but also pipeline replacement was necessary.

**Figure 2** DCVG + CIPS data of AL65 pipeline




**Note:** First and second HVG region is highlighted, respectively

**Figure 3** First HVG region of AL65 pipeline and the shape of corrosion

Calculating the %IR drop resulted from equation (2) reveals the following:

$$\Delta(\Delta G) = \Delta G_{0+0175.8} - \Delta G_{0+0169.5} = 27.1 - 1.4 = 25.7 \text{ mV} \quad (6)$$

$$\Delta P = V_{ON_{0+0169.5}} - V_{ON_{0+0175.8}} = 1470 - 1413 = 57 \text{ mV} \quad (7)$$

$$IR\% = \frac{25.7}{57} \times 100 = 45.1 \quad (8)$$

Comparing the resultant values calculated from equations (1) and (2), the obtained values from equation (2) is much closer to the direct inspection findings.

The OFF potential value of AL65 in the first and second HVG regions revealed an increasing mode that was contrary to ON potential value. This issue was related to more active polarization change at these regions while the CP current was interrupted. Consequently, it was considered that electrochemical activity associated with the exposed metal surface at damaged coatings areas were cathodic/anodic (C/A). In another word, the pipeline appeared to be protected while the CP system was ON and anodic when CP current was interrupted (OFF potential). It is known that metal beneath disbonded coatings may corrode even when the CP system is operating properly (NACE SP0502, 2008).

*4.1.3 IR drop of AL99A pipeline*

Table IV shows the recorded potential of AL99A at a high potential region. In a same trend, and contrary to the findings of direct inspection, the calculated IR result from equation (1) fails to predict the repair priority in the HVG region.

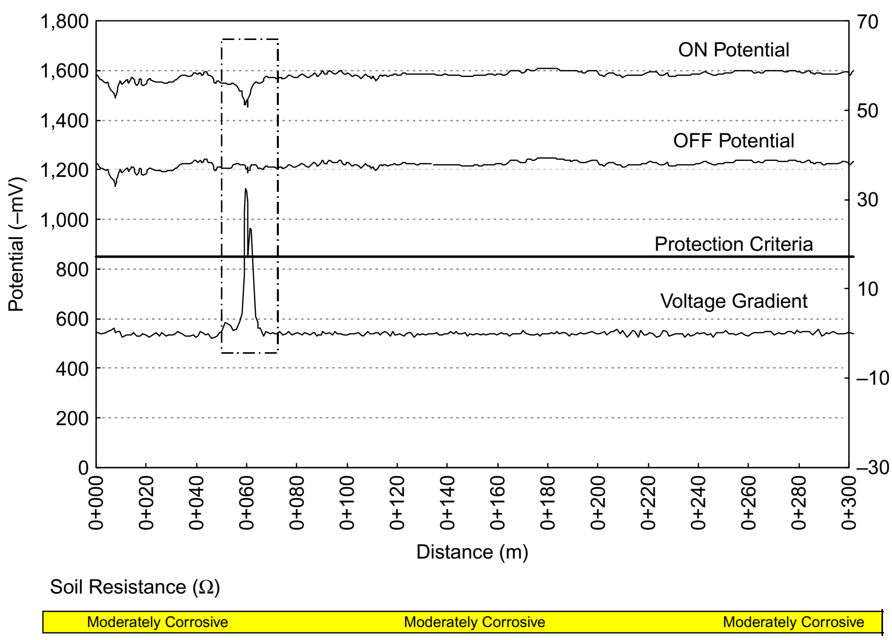
However, if the IR drop is calculated from equation (2):

$$\Delta(\Delta G) = \Delta G_{0+059.7} - \Delta G_{0+054.6} = 32.4 - 0.7 = 31.7 \text{ mV} \quad (9)$$

$$\Delta P = V_{ON_{0+054.6}} - V_{ON_{0+059.7}} = 1547 - 1463 = 84 \text{ mV} \quad (10)$$

$$IR\% = \frac{31.7}{84} \times 100 = 37.4 \quad (11)$$

**Figure 4** DCVG + CIPS data of AL99A pipeline




**Note:** HVG region was highlighted

**Figure 5** The HVG region of AL99A pipeline and the shape of corrosion

**Table II** Data of the first HVG region of AL65 pipeline and its related %IR calculated by equation (1)

| Chainage (m) | $V_{ON}$ (mV) | $V_{OFF}$ (mV) | $\Delta G$ (mV) | $\Delta V$ (mV) | IR% = ($\Delta G/\Delta V$) × 100 |
|---|---|---|---|---|---|
| **0 + 39.5** | 1,473 | 930 | 0.7 | 543 | 0.13 |
| **0 + 40.5** | 1,475 | 928 | 1.8 | 547 | 0.33 |
| **0 + 40.7** | 1,473 | 925 | 2.5 | 548 | 0.46 |
| **0 + 41.0** | 1,470 | 942 | 3.9 | 528 | 0.74 |
| **0 + 41.2** | 1,460 | 937 | 3.3 | 523 | 0.63 |
| **0 + 41.5** | 1,453 | 940 | 6.1 | 513 | 1.19 |
| **0 + 41.7** | 1,440 | 950 | 10.9 | 490 | 2.22 |
| **0 + 42.5** | 1,430 | 947 | 13.4 | 483 | 2.77 |
| **0 + 43.1** | 1,430 | 957 | 13.4 | 473 | 2.83 |
| **0 + 44.2** | 1,410 | 950 | 13.6 | 460 | 2.96 |
| **0 + 45.1** | 1,420 | 973 | 18.9 | 447 | 4.23 |
| **0 + 46.1** | 1,413 | 980 | 22.5 | 433 | 5.19 |
| **0 + 46.8** | 1,422 | 978 | 36.8 | 444 | 8.29 |
| **0 + 47.4** | 1,423 | 977 | 38.8 | 446 | 8.69 |
| **0 + 48.7** | 1,450 | 965 | 28.6 | 485 | 5.89 |
| **0 + 49.4** | 1,459 | 962 | 29.6 | 497 | 5.96 |
| **0 + 50.3** | 1,471 | 961 | 28.8 | 510 | 5.65 |
| **0 + 51.7** | 1,470 | 959 | 23.8 | 511 | 4.66 |
| **0 + 52.3** | 1,470 | 957 | 20.4 | 513 | 3.98 |
| **0 + 53.3** | 1,497 | 957 | 11.7 | 540 | 2.17 |
| **0 + 54.3** | 1,503 | 956 | 9 | 547 | 1.65 |
| **0 + 55.6** | 1,505 | 952 | 3.9 | 553 | 0.71 |
| **0 + 56.8** | 1,510 | 939 | 4.7 | 571 | 0.82 |

It can clearly been observed that the IR drop calculated from equation (2) is closer to the direct observation following excavation.

### 4.2 Corrosion attack

Figures 3 and 5 clearly show the form of corrosion attack on the pipeline. At first glance, pitting might be considered to be the form of corrosion. In order to have a clear understanding of this issue, XRD and EDS analyses were undertaken on the corrosion products (Figures 6 and 7). The results showed that the predominant oxides were hematite ($\alpha$-$Fe_2O_3$, dark red or dark-brown in contact with bare metal) and goethite ($\alpha$-FeO(OH), light red or red-orange in contact with pipe coating). The EDS results from the corrosion products did not show any sign of Cl anions (Figures 8 and 9), which suggested that corrosion was non-uniform localized general attack (Bagotsky, 2006).

**Table III** Data of the second HVG region of AL65 pipeline and its related %IR calculated by equation (1)

| Chainage (m) | $V_{ON}$ (mV) | $V_{OFF}$ (mV) | $\Delta G$ (mV) | $\Delta V$ (mV) | IR% = ($\Delta G/\Delta V$) × 100 |
|---|---|---|---|---|---|
| **0 + 169.5** | 1,470 | 942 | 1.4 | 528 | 0.27 |
| **0 + 170.1** | 1,460 | 937 | 2.4 | 523 | 0.46 |
| **0 + 170.8** | 1,453 | 940 | 4.2 | 513 | 0.82 |
| **0 + 171.5** | 1,440 | 950 | 15.4 | 490 | 3.14 |
| **0 + 172.4** | 1,430 | 947 | 13.7 | 483 | 2.84 |
| **0 + 173.1** | 1,430 | 957 | 9 | 473 | 1.90 |
| **0 + 174.1** | 1,410 | 950 | 13.2 | 460 | 2.87 |
| **0 + 174.8** | 1,420 | 973 | 18.8 | 447 | 4.21 |
| **0 + 175.8** | 1,413 | 970 | 27.1 | 443 | 6.12 |
| **0 + 177.2** | 1,428 | 968 | 19.6 | 460 | 4.26 |
| **0 + 178.2** | 1,435 | 957 | 16.4 | 478 | 3.43 |
| **0 + 178.8** | 1,453 | 955 | 6.1 | 498 | 1.23 |
| **0 + 179.5** | 1,463 | 952 | 1 | 511 | 0.19 |
| **0 + 180.2** | 1,470 | 952 | −1.5 | 518 | −0.29 |
| **0 + 180.8** | 1,475 | 952 | 1 | 523 | 0.19 |
| **0 + 181.6** | 1,480 | 947 | 2.4 | 533 | 0.45 |
| **0 + 182.7** | 1,490 | 947 | 2.6 | 543 | 0.48 |
| **0 + 183.8** | 1,503 | 952 | 1.7 | 551 | 0.31 |
| **0 + 184.3** | 1,505 | 950 | 0.5 | 555 | 0.09 |

**Table IV** Data of unique HVG region of AL99A pipeline and its related %IR calculated by equation (1)

| Chainage (m) | $V_{ON}$ (mV) | $V_{OFF}$ (mV) | $\Delta G$ (mV) | $\Delta V$ (mV) | IR% = ($\Delta G/\Delta V$) × 100 |
|---|---|---|---|---|---|
| **0 + 54.6** | 1,547 | 1,220 | 0.7 | 327 | 0.21 |
| **0 + 55.8** | 1,540 | 1,223 | 1 | 317 | 0.32 |
| **0 + 57.2** | 1,516 | 1,220 | 2.7 | 296 | 0.91 |
| **0 + 58.1** | 1,516 | 1,218 | 4.4 | 298 | 1.48 |
| **0 + 58.3** | 1,500 | 1,220 | 4.4 | 280 | 1.57 |
| **0 + 59.0** | 1,480 | 1,218 | 13.2 | 262 | 5.04 |
| **0 + 59.2** | 1,466 | 1,220 | 27.1 | 246 | 11.02 |
| **0 + 59.7** | 1,463 | 1,214 | 32.4 | 249 | 13.01 |
| **0 + 59.9** | 1,480 | 1,200 | 32 | 280 | 11.43 |
| **0 + 60.3** | 1,461 | 1,209 | 29.4 | 252 | 11.67 |
| **0 + 60.3** | 1,454 | 1,197 | 27.1 | 257 | 10.55 |
| **0 + 60.5** | 1,456 | 1,187 | 18.1 | 269 | 6.73 |
| **0 + 60.5** | 1,483 | 1,197 | 17.3 | 286 | 6.05 |
| **0 + 61.3** | 1,502 | 1,197 | 23.6 | 305 | 7.74 |
| **0 + 62.0** | 1,528 | 1,218 | 23.2 | 310 | 7.48 |
| **0 + 62.7** | 1,545 | 1,218 | 13.1 | 327 | 4.01 |
| **0 + 63.7** | 1,552 | 1,218 | 3.7 | 334 | 1.11 |
| **0 + 64.3** | 1,547 | 1,205 | 2.4 | 342 | 0.70 |
| **0 + 64.6** | 1,550 | 1,207 | 1.2 | 343 | 0.35 |

**Figure 6** X-ray spectra of the oxide layer taken from AL65 pipeline

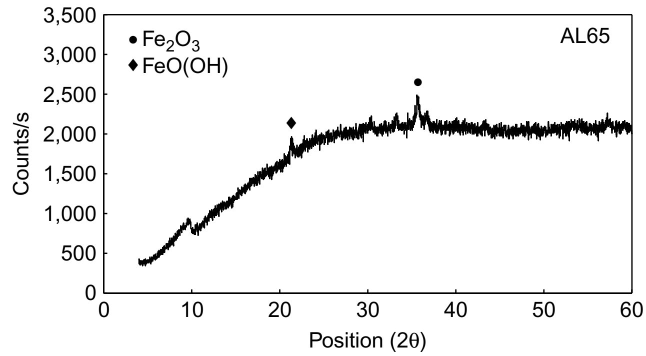



**Figure 7** X-ray spectra of the oxide layer taken from AL99A pipeline

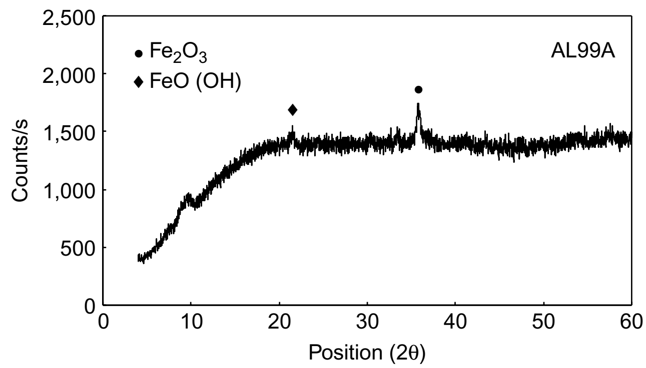
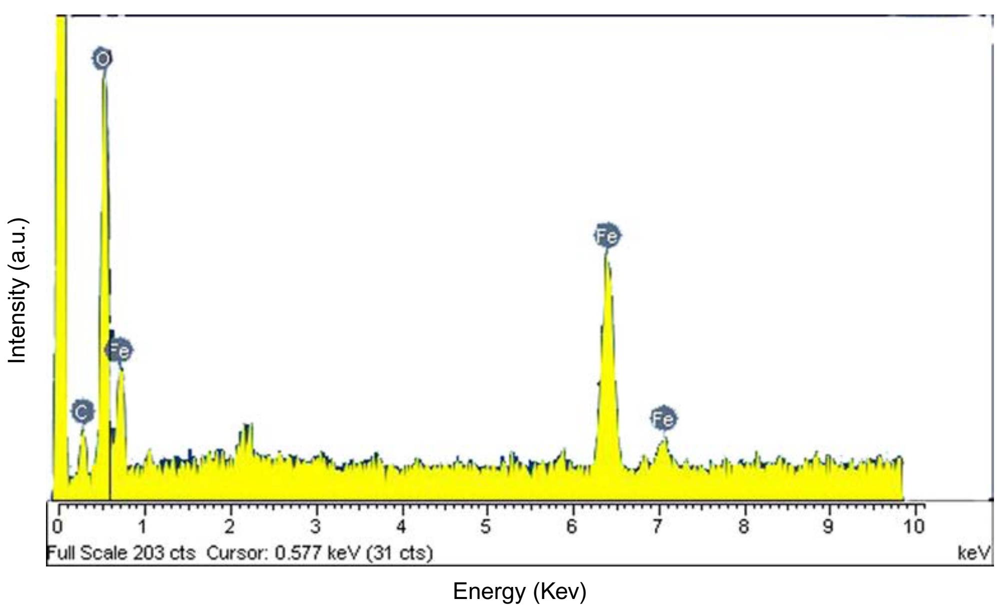



**Figure 8** EDS spectra of oxide at interface between oxide and pipeline coating

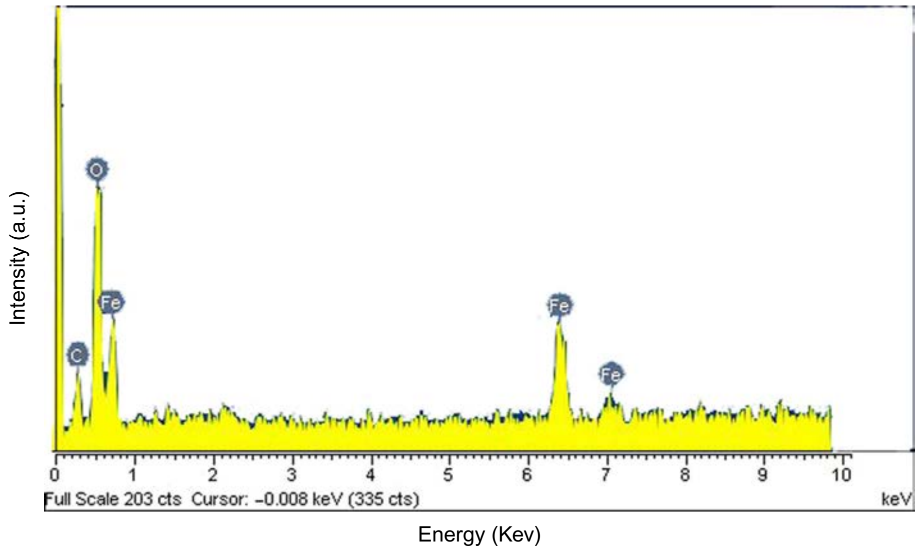



## 5. Conclusions

Direct inspections conducted after excavations showed that considerable contradictions existed between the predicted repair priority of critical coating faults and the outcomes of physical inspection. It was concluded that, the presently-used percentage IR calculation did not predict repair priority accurately and the consequent recommendations are unreliable. In consequence, a new empirical equation is proposed and repair predictions based on this calculation were checked extensively with direct inspection outcomes that proved acceptable correlation of its findings and actual repair priority.

Anti-Corrosion Methods and Materials
Volume 60 · Number 6 · 2013 · 312–318

**Figure 9** EDS spectra of oxide at interface between oxide and pipeline metal

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