CORROSION PREVENTION AND CONTROL IN HIGH PRESSURE OIL AND GAS TRANSMISSION PIPELINES

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1. INTRODUCTION:

At the start of the 1990s there were concerns over the increasing threat of corrosion to the integrity of high-pressure oil and gas transmission pipelines.

For example:

- Corrosion was the major cause of reportable incidents in North America[1]
- Corrosion was the major cause of pipeline failure in the Gulf of Mexico[2]
- Corrosion in a North American onshore oil pipeline had required over $1 billion in repairs[3]
- Internal corrosion along the complete length of pipelines had resulted in replacement[4].

However, the worldwide published failure statistics indicate that the incidents of corrosion are not increasing year on year[5-9]. Indeed, CONCAWE[8,9] statistics (for pipelines in Western Europe) show that the failure rate from corrosion (the most likely failure mode with increasing age) has not increased with pipeline age (Figure 1). In fact the statistics for gas pipelines in Europe, published

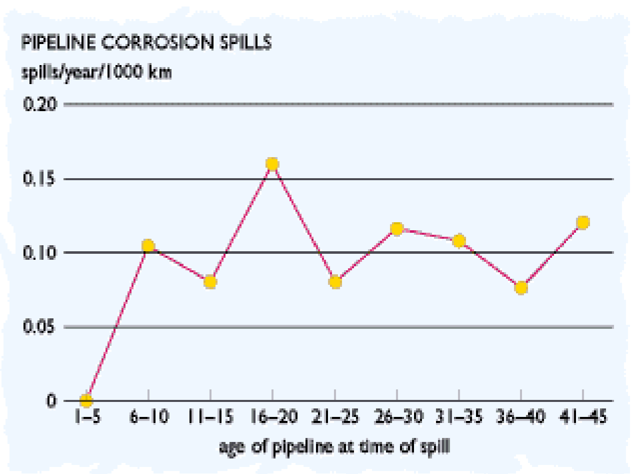


Figure 1 – Rate of Pipeline Failure Due to Corrosion

in the EGIG database, indicates that the number of incidents due to corrosion is actually decreasing.

The reason is the increasing use of corrosion management technologies to reduce corrosion risks. Indeed, it is now expected that pipeline operators utilise appropriate maintenance to prevent corrosion failures. For example, a North American operator has recently been fined a record $30 million because "corrosion caused most of the (300 oil) spills and they could have been prevented with proper operations and maintenance"[10].

This paper describes the successful corrosion management technologies which pipeline operators have adopted to prevent and control the threats of internal and external corrosion, including:

- risk based inspection (RBI) methodologies, which allow the principle threats to pipeline integrity to be identified and appropriate management plans defined,
- internal inspection, which allows corrosion to be detected before it causes failure,
- above ground surveys, which allow pipeline sections which are at risk from corrosion (coating faults, ineffective CP, low soil resistivity) to be identified,
- alignment of internal inspection and above ground survey data, which allows diagnosis of the cause of corrosion and adoption of mitigation measures, and
- comparison of repeat inspections to determine occurrence of 'new' corrosion and corrosion growth rates.

These methodologies are illustrated with actual examples of the rehabilitation and maintenance of pipelines at risk from corrosion worldwide.

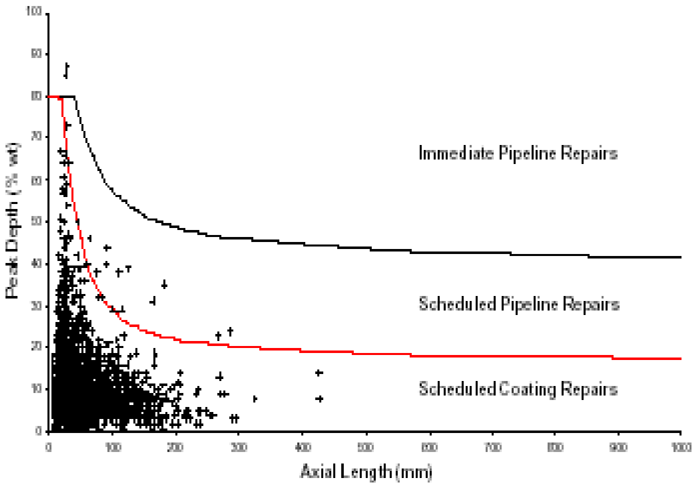
2- BACKGROUND:

Pipeline operators require a strategy for minimising corrosion risk and controlling the future and safe economic operation of a pipeline containing active corrosion.

It is now generally accepted that periodic internal (high resolution) inspection should be utilised to accurately detect, size and locate corrosion in a pipeline. When corrosion is detected the operator needs to know if the corrosion affects the integrity of their pipeline and when it would fail from further corrosion growth. This information allows the development of a future safe operating strategy (pipeline de-rating schedule and/or repair and/or replacement and/or re-inspection and/or corrosion inhibitor programmes, etc).

3- EXTERNAL CORROSION:

3.1 Prevention of External Corrosion:

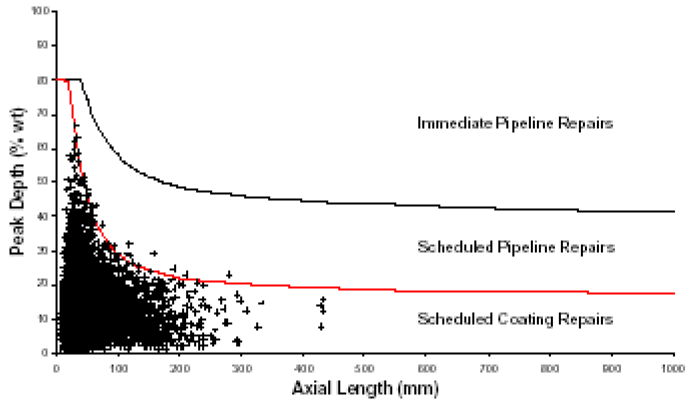


After Inspection 1

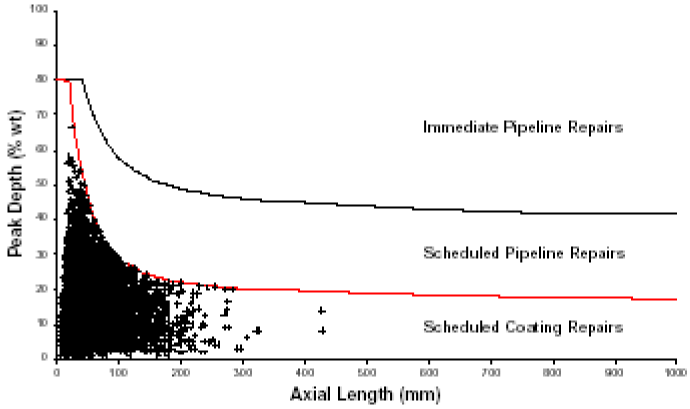
External corrosion results from coating and cathodic protection (CP) failure. For 'new' or rehabilitated pipelines, methods are available which minimise the risk of external corrosion occurring.

The pipeline coating is the first defence against external corrosion. In the event of faults in the coating, cathodic protection (CP) is utilised to maintain the pipeline at a potential where corrosion does not occur.

For new or rehabilitated pipelines, with a few faults, the current demand on the CP is low and the CP is highly effective. As the coating deteriorates it is necessary to increase the CP current.



Following Fitness-for-Purpose, remedial action & inspection 2



Following Fitness-for-Purpose, remedial action & inspection 3

Figure 2 – External Corrosion Control

However, because the distribution and size of coating faults is non-uniform it can be difficult to establish a uniform current; and eventually the extent of coating faults does not permit the CP system to be successfully adjusted/modified. In this situation it is not necessary to repair all coating faults. Proven methods are available[11] to identify the key coating faults whose repair will allow subsequent adequate CP protection.

It is highlighted that active corrosion under disbonded coating cannot be detected by existing above ground survey techniques[12].

3.2 External Corrosion Control:

When an internal inspection detects external corrosion the following strategy (Figure 2) is recommended. It is important to note that conducting pipeline and coating repairs can prevent further external corrosion.

(i) Define the size of corrosion that affects the immediate integrity of the pipeline and requires repair.

(ii) Estimate a realistic, future maximum corrosion rate.

(iii) Schedule the future requirements for pipeline and coating repair.

(iv) Determine the relationship between number of repairs and time as the basis for defining a re-inspection interval.

(v) After the second inspection (which can be a ‘short’ time after the first inspection for a pipeline with ‘extensive’ corrosion) repeat (i) to (iv) above. Comparison of the inspection findings will allow more accurate estimates of realistic, maximum corrosion rates. A ‘few’ scheduled pipeline repairs may be necessary. Scheduled coating repairs will be required. Finally the re-inspection interval will generally be extended.

(vi) Following future inspections only scheduled coating repairs (both (i) to prevent corrosion growing to a size which requires repair and (ii) to ensure the effectiveness of the CP) should be necessary.

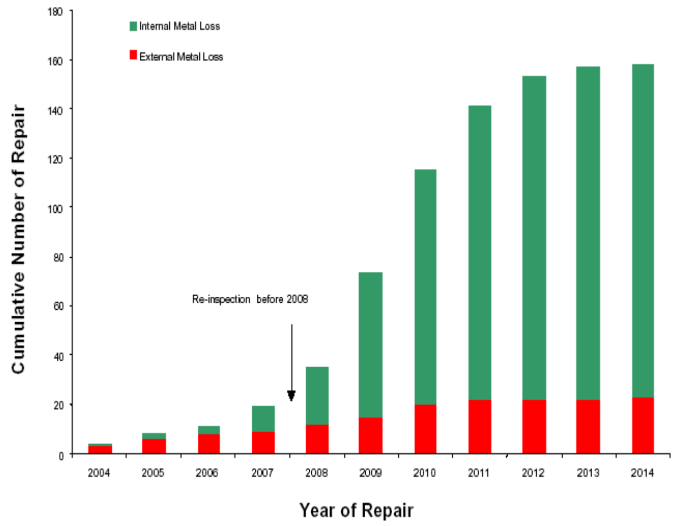


Figure 3 – Basis for Re-inspection Interval

The above strategy is designed to maximise the lifetime of the pipeline. If a shorter future lifetime is required, *e.g.* 3 years, a strategy should be devised which avoids the need for 'many' repairs in year 3 and ideally allows the pipeline to reach the end of its life in year 4.

The re-inspection interval should be selected before the number of estimated repairs increases dramatically (Figure 3).

Relating the number and scheduling of repairs to location along the pipeline can achieve cost effective pipeline and coating repair and ensure that mobilisation and repair costs are minimised by enabling more than one repair to be conducted at an excavation site.

4. INTERNAL CORROSION:

4.1 Prevention of internal corrosion:

Internal corrosion is due to the product transported. There have been many pipelines world-wide transmitting crude oil with water and carbon dioxide which have suffered internal corrosion. Internal corrosion is generally prevented by:

- Drying the product.
- Regular and effective pigging (cleaning and water removal).
- Injecting (continuous or batch) and appropriate inhibitor at the correct dosage.

It is important to note that once internal corrosion has occurred in a wet product pipeline it is very difficult to completely stop:

- Inhibitor needs to form a film (which is very difficult on an irregular (corroded) surface) to be fully effective.
- Corrosion products (particularly at the bottom of deep pits) can prevent inhibitor (even when continuously injected) reaching the corroding surface.

4.2 Internal Corrosion Control:

When an internal inspection detects internal corrosion the following strategy is recommended:

(i) Define the size of corrosion that affects the immediate integrity of the pipeline and make repair/replacement decisions.

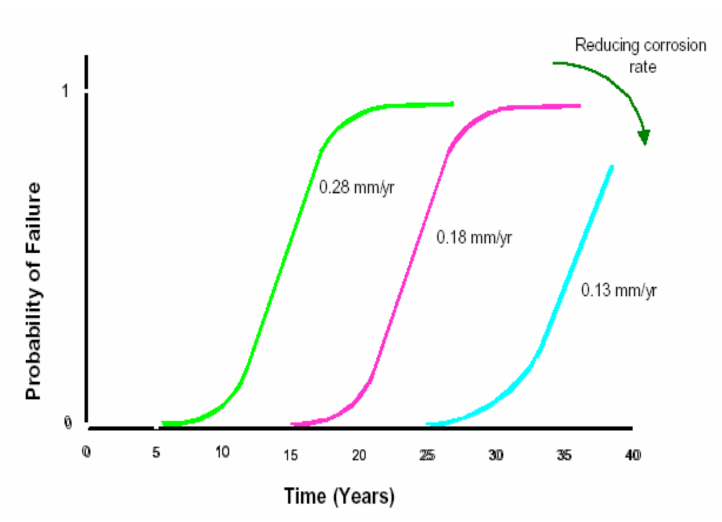


Figure 4 – Relationship Between Corrosion Rates and Remaining Life Using Risk Based Approaches

(ii) Estimate a realistic, future corrosion rate distribution. Because of the random nature of internal corrosion (see 4.1 above) it is generally ultra-conservative to assume a maximum corrosion rate for the future. Corrosion rates should be estimated from product composition and monitoring or if more than one inspection has been conducted, compare the increase in size of corrosion between inspections to estimate corrosion rates. The relevance of the estimated corrosion rates to future operating conditions should be confirmed.

(iii) Conduct probabilistic 'fitness-for-purpose' calculations (based on the inspection findings and estimated corrosion rate distributions) to determine the relationship between probability of failure and future lifetime. A typical example is presented in Figure 4.

5- <u>EXTERNAL/INTERNAL CORROSION</u>:

For a pipeline with combined external and internal corrosion a combination of the above strategies is required.

A recent example involved the assessment of a 25-year-old pipeline in Africa[13]. This onshore crude oil pipeline contained over 4 million internal and external corrosion defects. Assessing the corrosion to published guidance resulted in the need to replace the pipeline at a cost of over $300 million. A strategy was developed which allowed the pipeline to remain safely in service by conducting pipeline and coating repairs, CP upgrades, product monitoring and re-inspection within 2 years. The cost of this alternative rehabilitation strategy is $3 million.

6- <u>REPAIR DECISIONS</u>:

6.1 Selection of Assessment Methodology:

In the corrosion control strategies outlined in sections 3 and 4 above, the number of repairs required is dominated by the method used to assess the corrosion. The most appropriate method for the assessment of corrosion will depend upon the morphology of the corrosion being assessed, the properties of the pipe material and the orientation of the corrosion with respect to the hoop stress.

The most widely used and classical approach adopted by the industry for determining the remaining strength of corrosion and other metal loss defects is contained in ANSI/ASME B31G[14]. While the B31G criterion has been widely accepted and used, it is known to be excessively conservative in the case of modern pipeline steels. The assessment criterion was revisited in the late 1980s in an attempt to reduce its simplifying assumptions and associated conservatism. This work led to the RSTRENG 0.85 criterion (also known as the Modified B31G criterion) and the detailed RSTRENG method[15,16]. However, even these methods can be conservative for high strength steel and therefore the PCORRC[17] method and the Det Norske Veritas (DNV) RP-F101[18] method were developed for modern pipeline steels.

Using corrosion assessment methods that produce more accurate predictions of failure pressures will reduce the number of repairs required.

6.2 Selection of Repair Method:

In considering a repair method some techniques are technically and economically more suitable for specific defect types than others. Also, recent technical developments have meant that welded or “live” repairs have become less popular. This is due to the tight controls required during welding and that the long-term condition of the repair welds cannot be assessed with on line inspection technology. There is therefore a move worldwide to repair methods that do not require live welding onto the pipe, such as the Epoxy Sleeve Repair (ESR), or composite repairs such as the WrapMaster.

7- OTHER CONSIDERATIONS:

The previous sections have presented strategies for external and internal corrosion prevention and control. However, in order for a pipeline operator to make informed decisions in the development of these strategies, they need to be able to determine the root cause of the corrosion and understand the rate of growth of that corrosion. This next section provides information on two tools available to pipeline operators in this respect; data management software and inspection run comparison.

7.1 Data Management Considerations:

Traditional pipeline analysis and decision making for operations and maintenance often requires the collection, organisation, review and analysis of large quantities of disparate data. As more data is collected and analysed to support decision making, the quality of the decisions that are made increases. This is of particular concern when considering RBI methods, as the first stage in this process is the collection of data to assess the principle threats on the pipeline.

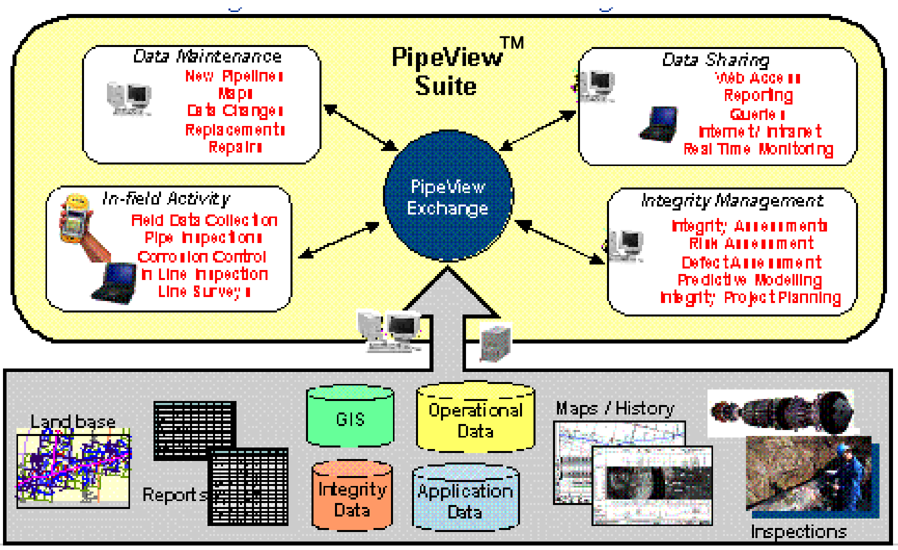


Figure 5 – Data Management Database Structure

Data management refers to the efficient collection, organisation and integration of disparate data. As data from inspections and routine maintenance has become more complex and larger in quantity, the manual management of data is not practical and automated tools are required in order to facilitate the process. With limited human resources and an unlikely decline in the growth of data quantity or complexity, operators are turning towards streamlined systems for organising and integrating data. Success of such systems is directly linked to scalability and the ability to foresee and deal with regular updates of inter-related data.

In the context of pipeline inspection and damage management, a tool is required to efficiently organize and align data from in-line inspections, above ground surveys and routine pipe inspections with information about the pipeline's properties, operating spectrum, and environmental characteristics. These data come from very different sources, and in order to enable the efficient use of the data one must establish a system that can tie all data types together and enable centralized access and analysis of integrated data. Once the system is in place, data can be efficiently loaded, aligned, and integrated into a data management system that enables access, distribution, visualization and analysis. The accurate alignment of the data is key to its success.

Figure 5 shows a schematic representation of such a data management system and illustrates some of the possible functions that can be streamlined via such a system.

7.2 Root Cause Analysis and Mitigation:

Assessing the significance of the corrosion or other pipeline damage, as defined in Sections 3 and 4, is only one part of the solution. In order to develop cost effective remediation and mitigation plans to prevent or limit further pipeline deterioration, it is also necessary to identify the root cause of the problem. Having all the relevant sets of data integrated is where a High Performance Data Management System really comes into its own allowing the integrity engineer to drill down and perform diagnostic assessments. The successful management and interpretation of the huge, independent and different formatted data sets is only possible with such a system.

7.2.1 External Corrosion Case Study:

As detailed in Section 3.1, in the majority of underground pipelines external coating and a Cathodic Protection (CP) system act synergistically to protect the pipeline such that if one fails the other continues to protect the pipeline. Consequently the alignment of ILI data and above ground survey data (CP and coating surveys) will enable the integrity engineer to identify the most likely locations on the pipeline where the corrosion is active.

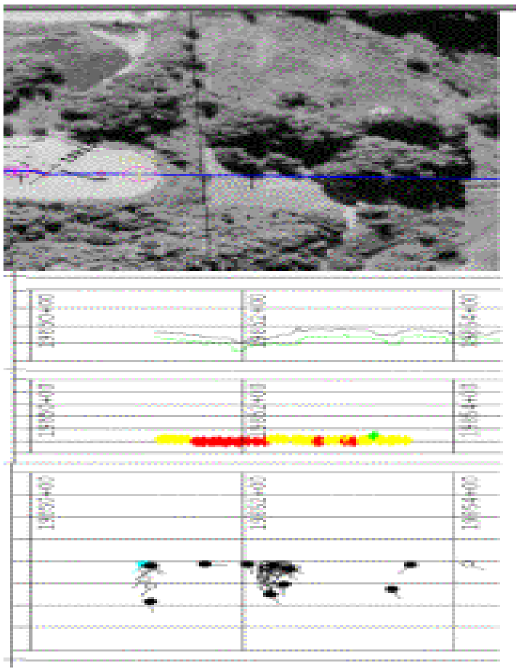


Figure 6 – Alignment sheet Showing ILI Feature Data, DCVG and CIS Results

For example, Figure 6 shows an alignment sheet for a section along the route of a 24" gas pipeline. Shown on the alignment sheet are (from bottom to top) the ILI feature data (in terms of RPR* severity), DCVG** results, CIS*** results and finally the pipeline map view showing the route of the line. In this example it is easy to see the correlation of the sub-critical corrosion features, coating faults and inadequate CP.

It is likely that the corrosion is active as both protection systems have failed. The maintenance manager has the following options:

i) Repair the corrosion now.
ii) Repair the corrosion in the future when it reaches a critical size.
iii) Upgrade the CP system now to arrest/limit further growth.
iv) Repair the pipe coating now to arrest further growth.

The addition of other data types into the data management system such as environmental data and soils data also helps with the diagnosis of root cause. For example, the presence of overhead power cables can disrupt the CP system and in extreme cases can cause AC induced corrosion. Other causes of CP interference can occur from nearby railways or even from the CP on other pipelines in the same corridor. Changing soil type can also affect the effectiveness of the CP and can be linked to the pattern of corrosion occurring along a pipeline.

* RPR is the Rupture Pressure Ratio = Predicted failure pressure / MAOP.
** DCVG = Direct Current Voltage Gradient, an above ground survey to detect coating faults.
*** CIS = Close Interval Survey, an above ground survey to measure the performance of the Cathodic Protection system.

7.2.2 Internal Corrosion Example:

The alignment of pipeline information e.g., facilities data (inlets, pump/compressor stations…), pipeline elevation, temperature profile etc enables predictions to be made of where internal corrosion will occur. The pattern of internal corrosion reported by an ILI tool can be aligned with this type of data to determine the cause of corrosion and to establish whether the corrosion is active or caused pre-service.

The alignment sheet displayed in Figure 7 shows a section along the route of a 36” wet gas pipeline. The alignment sheet shows the ILI data, the pipeline elevation and the map view. This example shows that the reported internal corrosion is coincident with a low spot in the line and is therefore associated with water drop out from the transported gas.

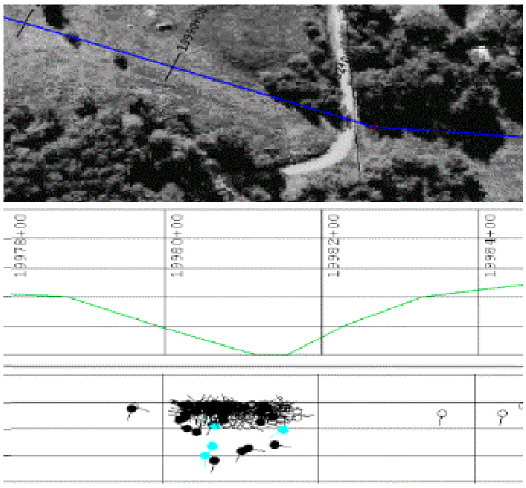


Figure 7 – Alignment Sheet Showing ILI Feature Data and Elevation Data

Potential remediation options include removing the cause of the problem (rather than repair especially if this problem is widespread) using water removal/cleaning pigs, chemical inhibition, using glycol or methanol to prevent and control hydrate formation etc. Following suitable mitigation treatment the level of internal corrosion can be monitored in the future using repeat ILI to determine whether the problem is under control. This type of approach is particularly useful for offshore pipelines where high costs make repair prohibitive.

7.3 Determination of Corrosion Rates:

In order to develop effective integrity management plans for corroding pipelines, operators need to be able to estimate realistic internal and external corrosion growth data. Corrosion growth rates are an essential input into future integrity assessments, rehabilitation planning and also allow safe and cost effective operating and maintenance strategies to be developed.

Pipeline corrosion growth rates can be estimated in a number of ways depending on the information available. Internal corrosion growth can be measured using in line probes and coupons. However, the results are highly dependent on the placement of the probes and coupons in the pipeline and can only provide average growth rates. Predictive models such as De Waard and Milliams[19,20] Cassandra[21] and Norsok[22] can also be used to estimate corrosion growth rates in 'sweet' oil and gas pipelines using operating data.

Unlike internal corrosion, which occurs in a closed system, the rate of the external corrosion reaction is influenced by a number of factors including the water content of the soil, the soluble salts present, the pH of the corrosion environment and the degree of oxygenation. Therefore the prediction of external rates is complex and there is currently no method for estimating corrosion rates using empirical equations. In the absence of any other data, the NACE recommended practice is to use a pitting corrosion rate of 0.4mm/yr[23] to determine re-inspection intervals when using External Direct Assessment methodologies. This rate represents the upper 80% confidence level from long–term underground corrosion tests of unprotected steel in a variety of soils.

One of the most accurate methods of obtaining actual corrosion growth rates is by comparing signals from subsequent high resolutions in-line inspections. A run comparison assessment provides a direct quantitative comparison of data from successive ILI inspections. There are several run comparison methods that can be conducted depending on the technology of the inspection and the format of the data. PII have developed the RunCom™ software which enables all of these types of run comparison to be conducted, allowing comparison of inspection data from the same inspection technologies (*e.g.* MFL/MFL), different technologies (*e.g.* MFL/USWM) or different vendors.

The first step in any RunCom™ assessment is a complex analysis of the discrete sets of data to guarantee that defects are correctly matched between runs. Initially, all detected areas of corrosion are matched based on linear distance to remove the inevitable and random, "along-pipe" errors caused by odometer slippage. The software also accounts for changes in construction that may have occurred during the survey interval allowing for such instances as new pipe joints or pipeline re-routing.

Having completed data alignment, successive survey data is presented in a multiple window format to allow the analysts to both qualitatively identify new areas of corrosion and growth, and then to quantify those growth rates by sizing the defects. The principle of signal matching using 2 sets of MFL data is illustrated in Figure 8. This figure shows how corrosion growth and new areas of corrosion can be identified between inspections.

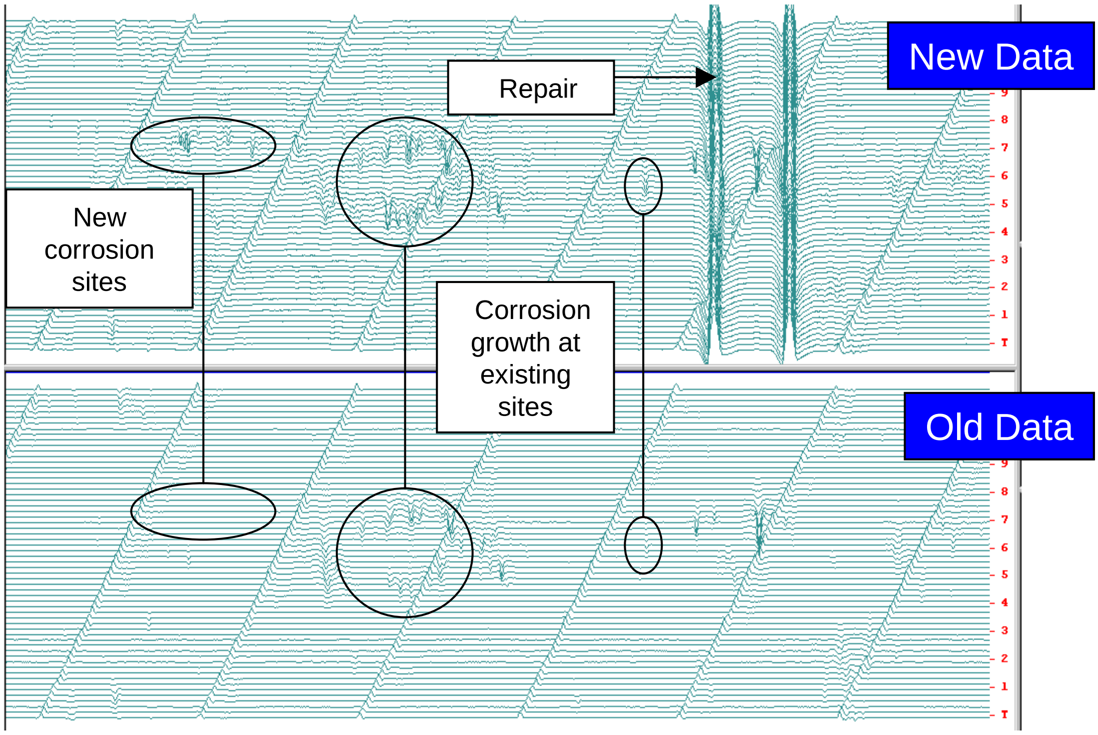


Figure 8 – Principle of Signal Matching Using RunCom™ and 2 Sets of MFL Data

8- CASE STUDY - PPC 12 INCH TANTA – MOSTOROD PRODUCTS PIPELINE:

Having presented the techniques and tools for developing corrosion control and prevention strategies, this section presents an example of how these principles are being put into practice by PPC on one of their products pipelines.

The PPC 12 inch Tanta – Mostorod pipeline was constructed between 1971 and 1972 and entered service in late 1972 transporting crude oil and petroleum products in both directions. The 12 inch, 0.344 inch wall thickness, Grade API 5LX52 pipeline operated at 50 bar (24% SMYS). The pipeline suffered corrosion failures between 1993 and 1998. During this period the pressure was progressively reduced from 50 bar to 20 bar. The pipeline was still suffering corrosion failures at 20 bar and taken out of service in 1998.

In early 2003, the pipeline was inspected (using the PII UltraScan WM™ inspection tool) to determine the condition as the basis for making a rehabilitation/replacement decision. The inspection reported:

- 5, 112 areas of external corrosion (including one leak) (see Figure 9),
- 42 areas of internal metal loss,
- 485 laminations,
- 84 dents,
- 3 shell repairs and
- 12 patch repairs.

PPC have developed a rehabilitation plan, to allow the pipeline to re-enter service at 50bar, involving the repair of 1,175 areas of external corrosion.

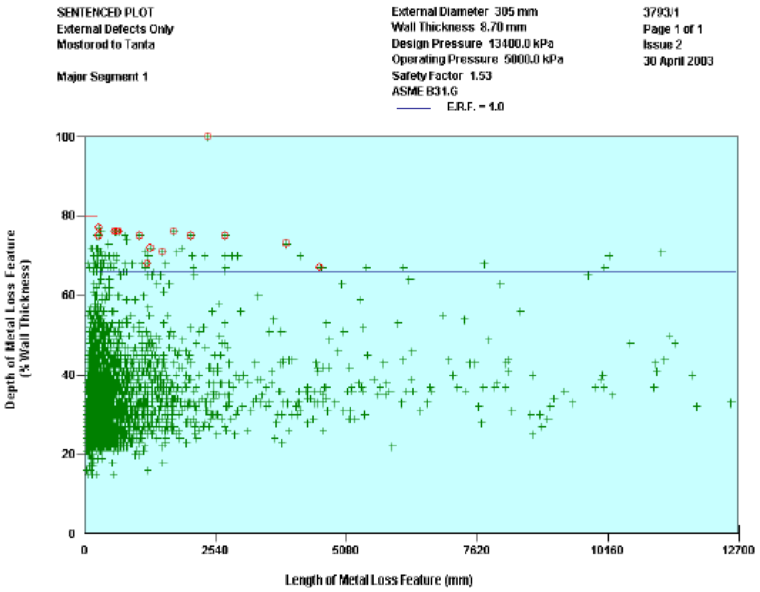


Figure 9 – Sentence Plot for Metal Loss Features

The plan involves the replacement of 30km section of pipeline that contains 400 of the areas of corrosion requiring repair. The new pipeline will loop the existing pipeline, which is now in the vicinity of building encroachments. The remaining 775 areas of corrosion require 234 individual repairs and 400 cutouts.

The rehabilitation plan takes into account future corrosion growth (utilising typical rates of 0.4mm/year that have been observed in similar pipelines).

In addition, the rehabilitation has been designed to ensure that all areas of corrosion that could threaten the integrity of the pipeline for a period of 5 years after the inspection are repaired.

The only other alternative for the pipeline was complete replacement. The replacement cost was estimated as 136.4 million L.E. ($22 million), which is over four times the cost of the above cost effective rehabilitation plan, 32.5 million L.E. ($5.25 million).

The rehabilitation has commenced and the pipeline is planned to re-enter service in 2006. Further studies are planned to develop long term cost effective maintenance plans to ensure the integrity of the rehabilitated pipeline using the technologies described in this paper.

9- CONCLUSIONS:

This paper has described the strategies, developed from 15 years experience, to prevent and control corrosion in pipelines. It is vital to use a combination of RBI, internal inspection, above ground surveys and product monitoring/inhibition, i.e. a customised package to control pipeline corrosion. In addition, in order to make informed pipeline decisions, it is vital to be able to combine pipeline data from different sources into an integrated data management system.

Strategies have been described to cost effectively rehabilitate corroding pipelines and maintain pipelines in ‘good’ condition.

ACKNOWLEDGEMENTS:

The authors would like to thank the management of EGPC, PPC and GE Energy for granting permission to publish this paper. In addition, the authors would like to acknowledge the assistance of Julia Race, Jane Dawson and Chad Zamarin in the paper preparation.

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