Development of Integrity Management Strategies for Pipelines

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Abstract

With the demand for energy from an ageing pipeline infrastructure, there is an increasing need to ensure the integrity of assets and extend their safe remaining life.

Gathering sufficient knowledge about the pipeline and knowing how best to analyse the available information has become critical to ensuring the long term integrity of pipelines. Inspection using in-line intelligent tools provides the clearest picture of the condition of the pipeline. The information gathered from these inspections can then support numerous integrity related activities:

- Corrosion Assessment
- Corrosion Growth Assessment
- Remnant Life Assessment & Corrosion Management Strategy

This paper describes the particular methodologies and demonstrates their application using experience gained with JADRANSKI NAFTOVOD (JANAF) Plc.

1. Introduction

The process of assessing the integrity of pipelines involves carrying out a detailed study in which the safe remaining life of a pipeline is determined and an integrity management plan is produced.

The focus of such an assessment is on a metal loss inspection of the pipeline using intelligent in-line inspection tools. The inspection findings are combined with a review of corrosion management activities in order to diagnose the likely causes of corrosion, or other damage, and identify appropriate preventative measures to minimise further deterioration of the pipeline. Based on determined corrosion growth rates, predictions of future repairs together with mitigation and re-inspection requirements can be determined. From this, pipeline operators are able to produce an optimised inspection, maintenance and repair strategy in order to ensure the integrity of their assets and extend their safe working life while improving pipeline safety and reliability.

This paper demonstrates the important role of in-line inspection data within the following key stages of an Integrity Management Strategy.

- Corrosion Assessment
- Corrosion Growth Assessment
- Remnant Life Assessment & Corrosion Management Strategy
The following sections describe the practical application of each of these activities using the case study of a pipeline section operated by JADRANSKI NAFTOVOD, Joint Stock Co. (JANAF Plc.) in Croatia.

2. Background to Case Study

JANAF Plc. based in Croatia, manage an international crude oil transportation system, designed and built in the period from 1974 to 1979, from the Port and Terminal of Omišalj, Island of Krk, Croatia supplying both local and foreign refineries in Eastern and Central Europe (Figure 1).

MACAW Engineering and ROSEN have worked with JANAF Plc. in developing their pipeline Integrity Management Strategy for several pipelines within their system. MACAW has produced integrity assessments of these pipelines based on in-line inspections performed by ROSEN. One such example is presented as a case study in this paper in order to demonstrate the particular methodologies of pipeline integrity assessment and their application. This paper has been developed in collaboration with ROSEN and JANAF Plc.

Figure 1: Overview of JANAF pipeline system route

The case study for this paper concerns the 179 km, 36” diameter section of the JANAF pipeline system from the Omišalj Terminal to the Sisak Terminal. Detailed information was provided by JANAF to enable a thorough assessment to be completed.
3. Corrosion Assessment

The aim of the corrosion assessment stage is the diagnosis of potential corrosion mechanisms. Data relevant to the assessment is collected including all available information relating to the basic design, operation, inspection, maintenance and repair information for the pipeline. For example:

- Pipeline location and route (pipeline elevation profile, satellite imagery data, etc.).
- Operational data (MAOP, MOP, product details, chemical treatments, etc.).
- Information on external coating types, specifications, application methods and any above ground coating survey data.
- Cathodic protection (CP) survey results.
- Previous internal and external inspection data for the pipeline
- Operational history and details of any repairs.
- Pipeline design and construction details (design criteria, pipe type/grade, wall thickness, weld data, hydro test conditions, etc.).
- Current integrity management plans for the pipeline, for example, current inspection strategy, routine maintenance activities, repair criteria, etc.

A review of the in-line inspection findings is performed in order to ascertain the current condition of the pipeline. By considering the shape (e.g. pitting, grooving) and location of corrosion within the line (internal, external, top-of-line, bottom of line, girth weld etc), and the collected data on the pipeline, the likely nature and characteristics of the reported corrosion are diagnosed. In this way the potential causes of corrosion that are a threat to the integrity of the pipeline can be identified.

3.1. Case Study

ROSEN Europe conducted a metal loss internal inspection of the JANAF pipeline segment from Omišalj to Sisak during May and June 2009, using the ROSEN Hi Res MFL & XYZ - Mapping Inspection Tool (CDG) and the Hi Res Axial Flaw Inspection tool (AFD). The pipeline was inspected in two separate sections, a 74.5 Km section between Omišalj and Dobra and a 104 Km section between Dobra and Sisak. The pipeline had previously been inspected by ROSEN in 2003 using the Corrosion Detection Pig (CDP).

3.1.1. Internal Corrosion

Internal corrosion in liquid hydrocarbon pipelines usually follows a distinctive distribution reflecting the origin and location of free water within the pipeline. Some of the consistent patterns of corrosion that occur in liquid pipelines are as follows:

Water Carry Over - Water enters the pipeline as a separate phase and creates corrosion in the bottom of the line immediately downstream of the inlet.

Water Separation - Water enters the pipeline as a water–in–oil emulsion which breaks down over time to cause corrosion in the bottom of the line some distance from the inlet.

Water Pooling - The corrosion distribution in a pipeline can be modified by water pooling at low points whether the origin is from carry over or separation.
Water Hold Up - If the elevation profile of a pipeline includes steep up-slopes in the direction of flow water hold – up can occur at the foot of these slopes. The corrosion distribution is similar to that for water pooling but the oil – water interface tends to be rather more turbulent and corrosion pitting can be concentrated at this interface.

The pattern of internal corrosion features within the pipeline was consistent with water carry over, water pooling and water hold up. The corrosion had developed immediately downstream from the inlet, diminishing with distance indicating water had entered the line in a separate phase, carried over from the Omišalj terminal. Local concentrations of corrosion were present depending on the topography of the line, with the water pooling at low points and water hold-up at the base of upslope sections. One such concentration is shown in Figure 2, where water pooling has occurred in the bottom of the pipeline at a low point in the elevation profile.

Figure 2: Corrosion Concentration at a Low Point in the Elevation Profile

The product within the pipeline has a very low water content of 0.1 – 0.2% v/v. The issues described above are not normally seen in lines where the water content is below 0.5% v/v. Therefore it was concluded that the distribution of internal corrosion features in this pipeline may have been caused as a result of operational issues at some stage during the life of the pipeline. Indeed, during a period of wartime from 1991 – 1995, the pipeline was left dormant with the product shut-in. Such conditions would have undoubtedly favoured corrosion via the pooling of water. Consequently, it was considered likely that the internal corrosion features were no longer active. This was investigated in detail during a comparison of the two sets of inspection data and the findings are discussed later in this paper.
3.2. External Corrosion

The pipeline is protected against external corrosion by an external coating and impressed current cathodic protection (CP) system. The coating on the longitudinally welded sections of the line is mill applied Densolene Polyethylene whereas for the spirally welded sections this coating has been field applied. Polyken tape has been used locally where repairs have been made.

The majority of external corrosion was reported in the bottom half of the pipeline and located in the spiral welded sections where a field applied tape coating had been applied. JANAF’s CP monitoring had shown that adequate protection levels were being achieved and therefore the most likely cause of the corrosion was CP shielding. CP shielding occurs in areas where wrinkling or sagging of the tape coating allows water and soil ingress beneath the coating. The cathodic protection system can become shielded from the active corrosion by the coating.

A concentration of external corrosion was associated with an above ground section of line where the pipeline is not protected by the CP system and the external paint coating is the only form of corrosion protection. Consequently, any coating defects in this area would have been at risk from atmospheric external corrosion and it is likely that this was the cause of the corrosion concentration. The corrosion in this area was identified at an early stage and the corrosion had not impacted on the integrity of the pipeline.

JANAF indicated that the pipeline was subject to stray current interference from numerous DC railway crossings. Stray currents can represent an external corrosion risk and it is understood that the pipeline was directly affected up to a distance of approximately 50 km and indirectly influenced up to a distance of approximately 100 km. To pro-actively counteract these effects JANAF performed a modernisation of the pipeline CP system by installing remote controlled transformer rectifier (T/R) units along the line in order to prevent corrosion in these areas. A key requirement of the inspection comparison was to review the effectiveness of these mitigation measures by confirming the extent of any corrosion activity in these sections of the pipeline.

4. Corrosion Growth Assessment

The corrosion growth assessment (CGA) is conducted in three stages:

- i. Feature Matching
- ii. Inspection Signal Comparison
- iii. Detailed Feature Resizing

Each stage of the CGA process is described in detail below.

4.1. Feature Matching

Feature matching involves the automatic comparison of two or more sets of inspection data using the feature list from each inspection. Before repeat sets of inspection data can be compared, they must first be aligned to a common ‘master’
distance. To ensure sufficient accuracy in the distance correlations, each girth weld should be matched in both of the inspections. Aligning two sets of data using other pipeline features such as valves, tees or bends may not provide a sufficiently accurate distance correlation.

Once the inspection data sets are aligned, they can be compared to identify features that have been reported in both inspections. For each corrosion feature reported in the recent inspection, the previous inspection data is reviewed to generate a list of possible matches. This process takes account of the errors associated with the axial and circumferential positions by defining a search window around the feature.

A flow chart showing the feature matching process is shown Figure 3.

**Figure 3: Feature Matching Process**

Feature matching provides a quick way of comparing repeat sets of inspection data and can provide useful information that is applicable to the whole pipeline, not just a sample of the reported features. However, all inspection tools contain a degree of
variation which will affect the accuracy of the information obtained from a feature matching exercise. Variations include:

- Reporting Threshold / Detection Capability
- Feature Sizing Accuracy
- Axial and Circumferential Location Accuracy

Unless the above factors are considered within the corrosion growth comparison, they can result in incorrect matches and unrealistic corrosion rates. Each factor is discussed below. The next stages of the corrosion growth assessment (Signal Comparison and Detailed Resizing) are aimed at removing / reducing the affect of these variations and improving the accuracy of the CGA. These are described under headings 4.2 and 4.3.

4.1.1. Reporting Threshold / Detection Capability

Inspection results tend to have a reporting threshold (typically 10% wt) imposed upon them due to the large number of shallow metal loss indications recorded. In addition, the sophistication of ILI tools has increased dramatically since their introduction approximately 40 years ago. Consequently, their ability to detect a given feature has also improved.

Both of these points should be considered when using the results of feature matching, since features that have been reported for the first time may have been present but not detected / reported by the previous inspection; they may not necessarily have grown.

This uncertainty is dealt with by conducting stages 2 and 3 of the CGA process; Signal Comparison and Detailed Feature Resizing.

4.1.2. Feature Sizing Accuracy

Currently, in-line inspection tools typically report general corrosion with an accuracy of ±10% of the wall thickness with a confidence limit of 80% i.e. 80% of the time, the reported depth will be within ±10% of the actual feature depth.

The accuracy of a comparison of the depths of a feature reported in two inspections is dependant on the sizing accuracy of both tools. An increase (or decrease) in the reported depth of a feature between inspections can therefore be attributed to either real corrosion growth or to variation in depth sizing in each inspection.

The sizing accuracy of each tool can be used to calculate the minimum corrosion rate that would be considered to be statistically significant. Below this statistically significant limit, an increase in reported depths can be attributed to either real corrosion growth or just variation in the sizing.

For example, consider a general corrosion feature located in 10.31 mm wall thickness pipe reported in both 2003 and 2009. Assuming both inspection tools have

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1 As defined by Pipeline Operator’s Forum ‘Specifications and Requirements for Intelligent Pig Inspection of Pipelines’. January 2005.
a depth sizing accuracy of ±10% wt at 80% confidence, then the accuracy of the calculated corrosion growth rate is ±0.22 mm/yr (95% confidence level).

This accuracy can be improved upon by conducting stage 3 of the CGA process; Detailed Feature Resizing.

4.1.3. Axial and Circumferential Location Accuracy

The location accuracy is dealt with in two ways in the feature matching process, firstly by aligning the features in terms of reported distance and secondly by using a search window to match features reported by the previous inspection, illustrated in Figure 4.

In addition, inspection vendors differ on how they report feature locations. For example some vendors use the top left corner of the feature ‘box’ (as seen in Figure 4) other report the centre of the ‘box’. When comparing multiple vendor inspections the feature data should be adjusted so that both / all inspections are referencing the same location.

**Figure 4: Example Demonstrating Search Window Technique to account for Location Reporting Accuracy**

4.2. Inspection Signal Comparison

This stage of the CGA involves the comparison of the raw inspection signals in order to validate the growth rates calculated by the feature matching process. Areas selected for signal comparison include; areas of high corrosion growth, apparent ‘new’ growth and corrosion ‘hotspots’. 
The signal comparison eliminates some of the uncertainties related to the feature matching process. It is possible to confirm whether features identified as ‘new’ by the feature matching were in fact present at the time of the previous inspection however were not reported as they were sized below the reporting threshold. The signal comparison also validates the matching process.

In order to accurately compare MFL signal data it is necessary to normalise the signal amplitude based on a fixed reference point (i.e. features that will not have changed between inspections), such as features that have been repaired by composite wrap, features that have been recoated immediately after the previous inspection, artificial defects or girth welds, (see Figure 5). The signal comparison is not limited to same vendor inspections, however additional data manipulation may be required such as re-orientation of the signals.

**Figure 5: Normalise Signal Amplitude Based on fixed reference Points such as Girth Welds**

![Signal Amplitude at Girth Weld](image)

An example signal comparison is shown in Figure 6 that shows growth of existing and new features.
4.3. Detailed Feature Resizing

In this stage a selected number of features identified in stages i) and ii), are subject to detailed analysis and re-sizing in order to ensure equivalent interpretation of the inspection signals in both inspections. This stage makes use of the latest sizing model and algorithm compensation and takes into account the assessment of systematic errors and a calibration correction. These processes are discussed in further detail below.

It should be noted that this process is conducted by the inspection vendor as access to proprietary software and sizing models is required. This type of analysis is only possible for repeat inspections by the same vendor.

4.3.1. Interpretation of Inspection Signals

Part of the data analysis process for a given feature involves the interpretation of the shape of the MFL signals. In certain instances, there may be more than one plausible interpretation. For example, a certain MFL signal shape could be caused by either one, wide feature or by two very close pinhole features. A difference in the interpretation of a given signal can result in a difference in reported depths.

4.3.2. Sizing Model and Algorithm Compensation

Sizing models and sizing algorithms are regularly reviewed and improved based upon additional pull-through tests and in-field verification data. The use of different sizing models or algorithms can result in small sizing differences. Therefore the older
sets of inspection data are re-analysed using the latest sizing models and algorithms.

4.3.3. Assessment of Systematic Errors and Calibration Correction

In addition to the small influence from varying sizing models, each ILI is affected not only by scattering of results, but also by small shifts or offsets of the calibration. These are referred to as systematic errors. These are corrected using verification data and features known to have remained the same between inspections, e.g. repaired features, artificial defects and milling features.

The detailed resizing process described above significantly improves the accuracy of the calculated growth rate. This is demonstrated by the example quoted previously where a corrosion growth rate calculated by the feature matching process would have an accuracy of ±0.22 mm/yr. The corrosion growth rate associated with this same feature following detailed resizing would have an improved accuracy of ±0.09 mm/yr (at 95% confidence).

4.4. Corrosion Growth Assessment Summary

Each stage of the CGA improves upon the accuracy of the previous.

Feature matching gives an indication of areas of highest activity and matched features give a good indication of the actual growth rate. However unmatched features can give an overestimate of corrosion rate as they may not be new growth but existing features that were below the reporting threshold of the previous inspection.

The signal comparison stage can confirm whether unmatched features are in fact evidence of new growth and eliminate any erroneous high rates. However the signal comparison is still dependant on the sizing accuracy of both inspection tools.

The detailed feature resizing ensures equivalent interpretation of the inspection signals and reduces the associated sizing errors, thus significantly improving the accuracy of the calculated corrosion rates.

4.5. Case Study

In the CGA conducted on JANAF’s pipeline all features were included in the feature matching process, the significant areas of corrosion growth identified by feature matching were then subject to signal comparison. From the findings of the signal comparison 101 features were selected for detailed resizing.

The CGA revealed that there was no evidence of internal corrosion growth throughout the pipeline, thus confirming the conclusions of the corrosion assessment that the internal corrosion occurred was historical and most likely occurred when the pipeline was shut in with product.
There was no evidence of significant corrosion growth in the areas believed to be affected by stray current. This confirmed that the control measures implemented by JANAF were mitigating the problem.

The CGA confirmed evidence of external corrosion growth in the spiral welded sections of pipe where a field applied tape coating was used. As described previously the CP monitoring data indicated that adequate protection levels had been achieved therefore the most likely cause of this corrosion was CP shielding.

Low level corrosion growth was identified on the above ground section that is not protected by the CP system.

4.5.1. Pipeline Segmentation

Local variation in ground and coating conditions along the pipeline route will lead to a variation in the rate of external corrosion growth. To reflect this variation, the pipeline was segmented for the application of corrosion growth rates in the future integrity assessment. The maximum growth rates for each segment were applied to all reported features within that segment. It is understood that the majority of features will grow at corrosion rates less than the maximum rate. However, the highest corrosion rates were confirmed during the CGA and due to the random nature of corrosion growth, it is not possible to identify features that may grow at these high rates in the future.

The segmentation was driven by the following contributing factors:

- Corrosion concentrations (hotspots)
- Corrosion growth rate
- Changes in consequences area
- Pipeline topography
- CP data
- Soil resistivity data
- Changes in coating type
- Changes of pipe manufacturer

5. Future Integrity and Corrosion Management Strategy

Based on the findings of the corrosion assessment and CGA described above, an effective future integrity and corrosion management strategy can be developed.

The corrosion growth rates are applied to the features, which are then assessed in terms of their impact on the immediate and future integrity of the pipeline using relevant code guidance (for example, Modified B31G, Detailed RSTRENG[2]). Defect assessment techniques are not described in detail within this paper. A schedule of future repairs is generated by this process.

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The active corrosion mechanisms identified by the corrosion assessment and CGA enable an appropriate mitigation / rehabilitation strategy to be developed. In the case of JANAF the active corrosion mechanisms identified were CP shielding and atmospheric corrosion on the above ground section where the pipeline cannot be protected by the CP system.

The above ground section was investigated and active external corrosion was identified. This was mitigated by sand blasting and application of an improved paint coating system in the affected areas.

It is not possible to mitigate against CP shielding therefore a sectional recoating / replacement schedule was developed based on calculated time to repair for individual features. In most cases sectional recoating prior to the date by which the features would require repair is a more cost effective solution than repair.

6. Conclusions

The main conclusions of this paper are:

1. The good communication links set up between operator, inspection vendor and consultant were key in developing a focused and effective Integrity Management Strategy.

2. The comprehensive historical and current pipeline data provided by JANAF enabled accurate diagnoses of corrosion mechanisms.

3. The detailed corrosion growth assessment clearly identifies the active and dormant corrosion mechanisms.

4. A very high degree of accuracy for calculated corrosion growth rates can be achieved by conducting signal comparison and detailed resizing.

5. The assessment conducted by MACAW demonstrated that the internal corrosion mitigation and stray current mitigation implemented by JANAF were effectively controlling corrosion activity.

6. The detailed corrosion growth assessment together with the detailed pipeline data allowed pipeline segmentation of high risk and high growth areas for appropriate application of growth rates in the future integrity assessment.

7. The corrosion assessment and corrosion growth assessment build up a very clear picture of the current condition of the pipeline and can be used to predict the future condition of the pipeline and any repairs and rehabilitation that may be required.

8. In most cases it is more cost effective to prevent or limit further growth by implementing corrosion control measures than it is to conduct repairs. Mitigation can be targeted at the active corrosion mechanisms identified by the assessment and a re-inspection interval can be set to confirm the effectiveness of such actions.