DIRECT ASSESSMENT TECHNIQUES FOR INTEGRITY MANAGEMENT OF UNDERGROUND PETROLEUM PIPELINES

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ABSTRACT

Direct assessment (DA) techniques for integrity management of underground petroleum (natural gas, crude oil, and refined products) pipelines address internal corrosion, external corrosion and stress corrosion cracking (SCC). These techniques are complimentary, and in some cases, a replacement for the two commonly used tools for integrity management, namely hydro static pressure testing and in-line inspection. This presentation provides an overview of these DA techniques and discusses requirements for developing, documenting, and implementing a Pipeline Direct Assessment Plan to evaluate the impact of these corrosion threats on pipeline integrity. The major steps highlighted in ASME, NACE, CEPA and related standards as well as current US federal regulations will be discussed. Some of the topics covered include data collection, feasibility, aboveground survey tools, direct examination, remaining life and re-assessment interval calculation and DA effectiveness.

TABLE OF CONTENTS

INTRODUCTION

The risk associated to the safe operation of gas and hazardous liquid transmission pipelines increases as the existing infrastructure ages, new environmental requirements are implemented and the population density around the piping systems increases. In the United States of America, The Pipeline Safety Improvement Act of 2002, which was signed into law on December 17, 2002, mandates significant changes and new requirements in the way that the natural gas industry ensures the safety and integrity of its pipelines. The law applies to natural gas transmission pipeline companies. Central to the law are the requirements it places on each pipeline operator to prepare and implement an "integrity management program," which among other things requires operators to identify so-called "high consequence areas (HCA)" on their systems, conduct risk analyses of these areas, perform baseline integrity assessments of each pipeline segment, and inspect the entire pipeline system according to a prescribed schedule and using prescribed methods. Companies were required to identify all HCAs by December 17, 2004, and submit specific integrity management programs to the Office of Pipeline Safety (OPS), Research and Special Projects Administration, U.S. Department of Transportation. All pipeline segments within HCAs needed to be inspected and remediation plans (if required) by December 17, 2008, while non-HCA segments must be inspected by 2012. All segments must be re-inspected on a 7-year cycle, with certain exceptions.

The cost of the legislation's requirements to natural gas pipeline companies alone was initially estimated to be $11 billion over 20 years.[1] Because the law allows OPS some discretion in the specification of assessment methodologies, OPS believed that the cost of implementation according to its specific rules will be considerably less-$4.7 billion over the same time period. OPS estimated first-year implementation costs of the new regulations to be about $0.036 per thousand cubic feet.

Management of pipeline integrity is a primary goal for operators and the development of the pipeline integrity management plan (IMP) is vital. The IMP provides information for an operator to effectively allocate resources for appropriate prevention, detection and mitigation activities that will result in improved safety and a reduction in the number of incidents and therefore will allow the operator to provide safe and reliable delivery of natural gas to their customers without adverse effects on employees, the public, customers or the environment.

The first step in managing integrity is identifying potential threats to the integrity. Gas pipeline incident data has been analyzed by the Pipeline Research Council International (PRCI) into 22 root-causes and each root-cause represents a threat to the pipeline integrity[2]. The threats have been group into 9 categories of related failure types according to their nature and growth characteristics, and sub divided into three time-related defect types: stables, time-independent and time-dependent.

At the time when Pipeline Safety Improvement Act of 2002 was signed into law, only two integrity assessment tools where available to evaluate the impact of the time-dependent threats on the pipeline integrity, in-line inspection (ILI) also known as smart pigs and hydrostatic pressure testing. Unfortunately, more than 50% of the existing pipelines in the US could not be assessed by ILI and the technical considerations and elevated costs (taking the line out of service, filling and disposal of test medium, and drying for gas transmission pipelines) associated to hydrostatic pressure testing presented a challenge to the pipeline industry.

As a respond to this challenge, industry experts developed the Direct Assessment (DA) methodology. DA is a structured process that combines data integration, use of existing survey tools, modeling for identifying areas where corrosion (internal, external of stress related) is most likely to occur and physical examination of the pipe. NACE International (former National Association of Corrosion Engineers) developed standards to provide guidance to pipeline operators when implementing DA.

This article provides an overview of DA methodologies, and discusses requirements for developing, documenting, and implementing a Pipeline Direct Assessment Plan to evaluate the impact of these corrosion threats on pipeline integrity.

DIRECT ASSESSMENT

DA is identified in the US Federal Regulation Gas Pipeline Integrity Management Rule as one of the three acceptable methods for evaluating the integrity of a pipeline segments. It is a methodology developed to evaluate the impact of three time-dependent threats on the integrity of gas and hazardous liquid on-shore pipelines. The methodology comprises of four steps: pre-assessment, indirect inspection, direct examination and post assessment. DA may be applied as a stand alone integrity assessment tool or may be used a complementary assessment to ILI or hydrostatic pressure testing. The industry standards related to DA are:

- NACE SP-0502 “Pipeline External Corrosion Direct Assessment Methodology”.
- NACE SP-0602 “Dry Gas – Internal Corrosion Direct Assessment Methodology”.
- NACE SP-0204 “Stress Corrosion Cracking Direct Assessment Methodology”.
- CEPA “Stress Corrosion Cracking Recommended Practices”.
- NACE SP-0208 “Liquid Petroleum – Internal Corrosion Direct Assessment Methodology”.
- NACE SP-0110 “Wet Gas – Internal Corrosion Direct Assessment Methodology”.
- TM-0109 “Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition”.
- NACE SP-0207 “Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines”.
- ASME B31.8S-2010 “Managing System Integrity of Gas Pipelines”.
- Multiphase Flow Internal Corrosion Direct Assessment Methodology – Under development. NACE Task Group TG426.

External Corrosion Direct Assessment (ECDA) is based on the principle that external metal loss associated to corrosion occurs at locations where the protective coating breaks (also known as holidays) and the steel is exposed to the external environment. The ability of the aboveground tools, e.g. close interval potential survey (CIS or CIPS) and direct current voltage gradient, to identify sections along the pipeline segment having the highest likelihood of corrosion activity, allows for classification and prioritization of areas where the pipe is exposed to evaluate the extend of the external metal loss and calculate the remaining life of the pipeline segment.

Internal Corrosion Direct Assessment (ICDA) is based on modeling the flow of the product transported; identifying sections where water, solids or both may accumulate along the pipeline segment. At these locations, the pipe is exposed and the impact of internal metal loss is assessed with direct examinations.

Stress Corrosion Cracking Direct Assessment (SCCDA) is based on analysis of the pipeline operation conditions, i.e. operating stress level, pressure fluctuations and temperature, the type of coating, age and external environment to prioritize potentially susceptible segments and select specific sites for excavation. ASME and CEPA documents provide criteria for identifying potential susceptible segment for high-pH SCC and near-neutral SCC respectively.

A gas pipeline segment is considered to susceptible to high-pH SCC if all of the following factors are met:

- The operating stress exceeds 60% of the specified minimum yield strength (SMYS);
- The operating temperature has historically exceeded 38 ºC (100 ºF);
- The segment is less than or equal to 32 kilometers (20 miles) downstream from a compressor station;
- The age of the pipe is greater than or equal to 10 years; and
- The coating type is other than fusion-bonded epoxy (FBE)

The same factors may be used for liquid petroleum pipelines, considering the distance downstream from pump stations.

DA methodologies are continuous improvement processes; through successive application, DA should identify and address locations at which the threat of corrosion has occurred or is occurring.

PRE-ASSESSMENT STEP

The objectives of the Pre-assessment Step are to determine whether DA is feasible to assess the impact of time-dependent threats on the pipe segment under study; for external and internal corrosion identifies DA regions and for external corrosion it also selects indirect inspection tools.

The main activity of the Pre-assessment Step is data collection; historical (over the life of the pipe) and current data along with physical information of the segment to be evaluated. Data from the following five categories should be collected and analyzed:

- Pipe related;
- Construction related;
- Soil / Environment for external corrosion and stress corrosion cracking (SCC);
- Corrosion control; and
- Operational data.

The data collected in the Pre-assessment Step often includes the same data typically considered in an overall pipeline threat assessment. Depending of the IMP, the pipeline operator may conduct the Pre-assessment Step in conjunction with a pipeline risk assessment.

DA Feasibility

Based on the characteristics of individual pipeline segments, operators may define the minimum data requirements to consider whether or not the DA process is feasible. When the minimum data required is not available, the pipeline operator should not assess the pipeline integrity with DA.

For ECDA, conditions that may limit the sensitivity of aboveground surveys, e.g. shielding coating, depth of burial and frozen ground, may preclude the use of ECDA.
Conditions that may preclude the use of Dry Gas ICDA (DG-ICDA) as an integrity assessment methodology are, within others, pipeline should not normally contain water or glycols, should not have corrosion protection internal coating, should not be susceptible to top of the line corrosion and corrosion inhibitors should not be used.

An important aspect of DA is associated with the need to excavate and expose the pipe segment to physically inspect the surface of the steel; therefore DA is not feasible where access to the pipe does not exist or is limited.

ECDA Indirect Inspection Tool Selection

The selection of ECDA indirect inspection tools is based on the ability of the tools to detect corrosion activity and coating damage with high degree of confidence under the specific pipeline conditions in which they will be applied. A minimum of two complementary survey tools is required over 100% of the pipeline segment. Table 2 of NACE SP-0502[3] provides guidance on selecting indirect inspection tools and specifically addresses conditions under which some indirect inspection tools may not be practical or reliable.

ECDA Region Determination

The definition of an ECDA region is a section or sections of a pipeline that have similar physical characteristics, corrosion histories, expected future corrosion conditions, and in which the same indirect inspection tools are used. An example of ECDA region determination on a pipeline segment is presented in Figure 1.

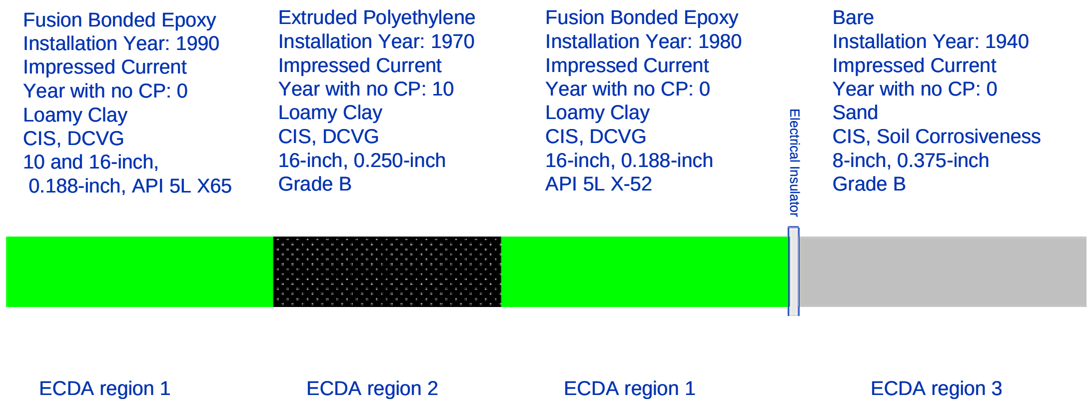

Figure 1: Example of ECDA region determination

As can be seen in Figure 1, ECDA regions are not related to the geographical location but to physical characteristics and corrosion history. This represents a key step in ECDA process as the predictive model that will be developed to classify the holidays within the same ECDA region, assumes that holidays classified as minor, moderate and severe will have similar characteristics respectively within the ECDA region.

ICDA Region Determination

A DG-ICDA region is a portion of a pipeline with a defined length. A defined length is any length of pipe until a new input introduces the possibility of water entering the pipeline. Input changes also include new direction of gas flow. In the case of bidirectional flow history, DG-ICDA regions should be identified for each flow direction, and each flow direction should be treated separately. Figure 2 shows an example of a pipeline segment with bidirectional flow and 4 gas inlets.

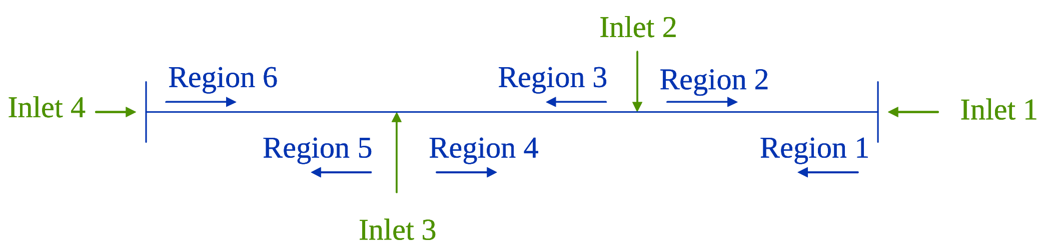

Figure 2: Example of DG-ICDA region determinations on a pipeline segment with bidirectional flow and 4 gas inlets.

NACE standards provide guidelines to establish ECDA regions for dry gas, liquid petroleum and wet gas.

The number of ECDA and ICDA regions impacts the number of excavations and direct examinations required to complete the DA process.

As mentioned above, SCCDA Pre-assessment Step consists of review and analysis of pipeline operation conditions, i.e. operating stress level, pressure fluctuations and temperature, the type of coating, age and external environment to prioritize potentially susceptible segments and select specific sites for excavation and direct examination.

INDIRECT INSPECTION STEP

The objective of the Indirect Inspection Step is to identify areas along the pipeline segment where corrosion may have occurred or may be occurring.

For an ECDA process it will include identification and classification of coating faults (normally referred to as "indications"). It requires the use of at least two aboveground survey tools over the entire length of each ECDA region and includes performing the surveys, aligning and comparing data, and developing the indication severity classification. Figure 3 presents guidelines for classification of indications.

Severity Classification	
Severe	Indications that the pipeline operator considers as having the highest likelihood of corrosion activity
Moderate	Indications that the pipeline operator considers as having possible corrosion activity
Minor	Indications that the pipeline operators considers inactive or as having the lowest likehood of corrosion activity

Figure 3: Guideline for indication severity classification

For DG-ICDA and WG-ICDA the Indirect Inspection Step will include multiphase flow calculations using collected data to determine the critical inclination angle of liquid holdup for each ECDA region, producing a pipeline inclination profile, and identifying sites where internal corrosion may be present.

For LP-ICDA the Indirect Inspection Step will include multiphase flow calculations using collected data to determine the critical velocities and inclination angles of water and solid accumulation for each ECDA region, producing a pipeline inclination profile, and identifying sites where internal corrosion may be present.

When conducting an SCCDA, the Indirect Inspection Step consist of aboveground surveys to supplement Pre-assessment data and then use these data to prioritize susceptible segments and select specific sites for excavation and direct examination.

DIRECT EXAMINATION STEP

The objectives of the Direct Examination Step are to examine the pipe at location chosen for excavation, assess the extent and severity of corrosion, identify the root-cause of corrosion (when found) and calculate the remaining strength.

For ECDA and SCCDA the following information is normally recorded at excavation sites:

- Coating system is identified, condition assessed (adhesion, disbondment) and coating faults mapped;
- Cathodic protection level;
- Soil characterization and sampling;
- Sample collection of electrolyte/deposits around holidays;
- Chemical analysis of deposits/electrolyte;
- Identification and measurement of corrosion defects (corrosion mapping);
- Identification of seam weld type;
- Identification and measurement of other pipe defects such as dents and gauges;
- Magnetic particle inspection to identify linear indications; cluster identification
- In-situ metallography to establish type of SCC;

- Pipe wall thickness and diameter; and
- Photographic documentation.

When conducting an ECDA and external metal loss is found the remaining strength of the pipe is calculated using B31G[4], RSTRENG[5] or DNV-F101[6]. If the remaining strength of a defect is below the normally accepted level for the pipeline segment (i.e. the maximum operating pressure multiplied by a safety factor), a repair or replacement may be required.

When conducting SCCDA, each detected cluster should be labeled with a unique identification and the location of the center of the colony should be identified relative to a reference point such as a weld and a clock position. The precedence of significant cracking should be identified using the guidelines provided by CEPA SCC recommended practice[7].

The ICDA Direct Examination Step is performed to determine whether internal corrosion exists at the locations selected in the previous step and to assess the overall condition of each ICDA region. The locations with inclinations greater than the critical angle are examined moving downstream from the beginning of the ICDA region. Two consecutive locations must be found free from internal corrosion to complete the assessment. Internal corrosion metal loss is considered significant if the remaining wall thickness is less than the minimum specified nominal. Non destructive testing (NDE) should be performed at the dig sites to determine the remaining wall thickness of the pipe; remaining strength calculations should be performed as indicated above for the ECDA process.

POST-ASSESSMENT STEP

The objectives of the Post-assessment Step are to define reassessment interval, and assess the overall effectiveness of the DA process.

When significant SCC is found, the SCCDA Post-assessment Step determines the type of mitigation; if the SCC is considered to be localized then a pipe replacement or repair may be necessary. However, when general SCC is identified the mitigation may require the use of ILI or hydrostatic pressure test, followed by pipe repair and or replacements.

NACE ECDA and ICDA standards provide guidelines to calculate the remaining life of the pipe based on the data collected in the Direct Examination Step and based on these results it recommends half of the remaining life as the re-assessment interval. For gas transmission pipelines in the USA, the maximum re-assessment interval is defined by the federal government.

As part of the DA validation and to evaluate its effectiveness of the process, the data obtained in the first three steps is analyzed and compared. When the methodology is applied for the first time more stringent procedures are put in place and additional excavations and direct examinations are conducted. The process identifies areas of improvement for future applications the integrity assessment process is completed.

SUMMARY

The DA methodology has been applied in the USA since the early 2000’ and has proved to be cost effective alternative to ILI and hydrostatic pressure test for pipeline systems that where not built to run ILI tools.

A disadvantage of DA is that it only assesses three of the 21 pipeline integrity threats identified.

One significant benefit that is not provided by ILI and hydrostatic pressure testing is that the root-cause of the metal loss is identified and mitigation activities are recommended to reduce the impact of corrosion on the integrity of the system.

DA can also be applied as a supportive methodology when ILI and or hydrostatic testing are used as the integrity assessment tool.

REFERENCES

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0. RSTRENG “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe”.
0. DNV Recommended Practice RP-F101 “Corroded Pipelines”.
0. CEPA “Stress Corrosion Cracking Recommended Practices”

LIST OF FIGURES