Sridhar Srinivasan, Honeywell International, Inc., USA, discusses the use of direct assessment methodology to accurately predict and monitor internal corrosion in pipelines.

It is well known that internal corrosion in gas, liquid and multiphase transmission pipelines is a major problem that causes extensive damage to pipelines and operating facilities around the world. As a result of the incidents caused, new regulations have been created. For example, the 49 CFR 192 (Sub. O) states that the threat of internal corrosion in a natural gas pipeline system is assumed to exist until an operator can demonstrate otherwise, either through direct assessment, inline inspection, hydrostatic pressure test or some other technology. This has led to a substantial acceptance of new direct assessment and pipeline integrity focused work by the industry.

The National Association of Corrosion Engineers (NACE) has ratified Internal Corrosion Direct Assessment (ICDA) methods for dry gas, wet gas and liquid product pipelines to meet the need for pipeline integrity with respect to likelihood of internal corrosion. ICDA is designed to prioritise the likelihood of corrosion along a pipeline and identify locations most susceptible to internal corrosion damage. These prioritised critical locations are then excavated and examined, and results of these inspections are used as the basis for assessing the integrity of the complete pipeline. In effect, inspection data from a select few locations
along the pipeline is used to characterise integrity of the entire pipeline. Performing successful ICDA applications relies heavily on the ability to model flow and accurately quantify/predict corrosion damage along the pipeline. Although it is necessary, the presence of aqueous electrolyte-like water or a conductive medium alone is not a sufficient condition for internal corrosion damage to occur in wet or dry gas pipelines. Other operating characteristics of the pipeline, such as in-situ pH, acid gas content, pressure and temperature also have a significant impact on the magnitude of corrosion. Even though the presence of liquid water provides a necessary medium for corrosion to occur, the actual parametric conditions, flow dynamics and composition of the transmitted gas affect the extent of corrosion.

**Explaining ICDA**

Direct assessment (DA) consists of three areas: External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA) and Stress Corrosion Direct Assessment (SCCDA). All three DA methodologies are aimed at proactively improving pipeline safety by assessing the risk and reducing the impact of the corrosion threat being addressed. These are designed to be cost-effective integrity management tools that complement detailed inspections, such as inline inspection (ILI) and hydrostatic test.

ICDA has been further classified into three areas: Dry Gas ICDA, Wet Gas ICDA and Liquid Petroleum ICDA. Multiphase ICDA is currently in the works and focuses on onshore and offshore pipelines that carry multiphase fluids. These methodologies use a four step continuous improvement process detailed as follows:

- **Pre-assessment**: this step focuses on collecting historic and current operating data about the pipeline, which determines feasibility of application and defines ICDA regions for further analyses.
- **Indirect inspection**: this step includes the use of appropriate modelling tools and techniques for prediction and prioritisation of overall corrosion severity at different locations (assessment sites) along a pipeline segment to undergo detailed examination.
- **Direct examination**: this step includes performing actions for detailed examination of assessment sites prioritised to have the highest corrosion severity identified in the indirect inspection step. Detailed examination of the internal surface of a pipe involves non-destructive examination (NDE) methods sufficient to identify and characterise corrosion rates and wall losses.
- **Post-assessment**: the post-assessment step covers analyses of data collected from the previous three steps to assess the effectiveness of the ICDA process, determine reassessment intervals and establish corrosion control strategies.

The successful application of each of these steps relies heavily on the proper application of the preceding step, with a focus on collecting all relevant data and operating history in the pre-assessment step and using the right tools and technology in the indirect inspection step.

Dry Gas Internal Corrosion Direct Assessment (DG-ICDA) is an industry-standard methodology (NACE SP0206) designed to provide preventive maintenance and protect against costly pipeline failures. Gas transmission pipelines under normal operating conditions carry under-saturated gas processed by upstream dehydrating units. These pipelines are generally operated with no protection or inhibition and rely on the performance of the dehydrating units to process gas within acceptable standards. It is typical for some instability or other process disturbances to result in near saturated gas or have some liquid water carryover in such pipelines. These upsets lead to water accumulation in some parts of the pipeline farther downstream, or cause water condensation due to pressure and temperature changes along the length of the pipeline.

Wet Gas Internal Corrosion Direct Assessment (WG-ICDA) is a structured process that combines pre-assessment, indirect inspection, detailed examination and post-assessment to evaluate pipeline integrity threats as a result of internal corrosion. The goal of WG-ICDA is to identify locations with the greatest likelihood of internal corrosion, due to factors such as water content, flow regime, liquid holdup,
temperature and pressure changes. Honeywell’s Predict®-Pipe system facilitates easy automation of DG-ICDA (SP0206) and WG-ICDA per NACE Standard Practice Document SP0110. The programme identifies the most probable locations (MPLs) along a WG-ICDA region to determine the position of assessment sites. These assessment sites are selected where internal corrosion damage has been identified through:

1. Available historical information.
2. Flow modelling to determine liquid holdup.
3. Flow regimes.
4. Internal Corrosion Predictive Models (ICPMs) to evaluate internal corrosion rates.

**Current challenges**

The primary assumption of most gas pipeline operators is that internal corrosion does not exist in their pipelines. This is a difficult contention to corroborate without a detailed assessment and evaluation. On the contrary, internal corrosion is very likely to exist in measurable quantities where there is a presence of liquid water and acid gases.

Furthermore, the actual areas that are affected by corrosion in dry gas pipelines are small compared to the lengths of pipeline transporting gas, making it difficult to locate and mitigate corrosion. Using ICDA techniques provides the operator with tools to focus inspection resources where they are needed and help make integrity assessments on the entire pipeline.

ICDA relies on identifying most susceptible locations along the pipeline and inspecting these locations. Dry Gas ICDA (DG-ICDA) prioritises inspection sites based on the likelihood of water accumulation, whereas Wet Gas ICDA (WG-ICDA) prioritises inspection sites based on water holdup and predicted corrosion rates. Based on the inspection results of these inspection sites, the integrity of remaining pipeline is assessed.

Operating parameters such as gas flowrate, pressure, temperature and pipe ID are used to calculate the critical angle requirements for DG-ICDA. The selection of the most representative operational conditions for DG-ICDA modelling is critical because typically pipeline operating conditions are dynamic and change with seasonal variations and load requirements.

WG-ICDA relies heavily on the ability of the ICPM to accurately predict corrosion rates as a function of flowrate, acid gas composition, water composition, in-situ pH, scale protection and water holdup. The ability to classify sub-regimes based on changes in flow regime is a critical aspect of facilitating a successful WG-ICDA programme.

Using an ICPM that provides the ability to evaluate both the flow dynamics of the pipeline to calculate flow regimes and liquid holdup along with an accurate corrosion prediction simplifies the process and enhances the accuracy of identifying locations that can be prioritised for inspection.

The incremental value of correctly characterising the flow simulation significantly outweighs the value of high precision electronic elevation modelling or GPS surveys. The selection of an advanced flow and corrosion prediction model forms a key component in the completion of a successful ICDA programme.

**The ideal solution**

DG-ICDA has been widely implemented across the gas pipeline network in the Americas by many pipeline operators. There have been mixed reports regarding the success and value of these programmes. According to some, the process has been found to be highly effective for evaluating pipeline integrity with respect to the internal corrosion threat. The overall effort required to implement DG-ICDA is not significantly more or less than any other integrity assessment processes. However, WG-ICDA was ratified only two years ago and reports about its implementation and experience are not readily available in the industry. ICDA provides a robust framework for performing cost-effective integrity assessments, and advanced technology based flow and corrosion models vastly enhance this process to ensure the area of corrosion is found without unnecessary digging or random inspection.

The ideal solution should incorporate four broad technologies: multiphase flow modelling, corrosion prediction, using current ICDA methodology and real-time corrosion monitoring. These types of technologies are capable of not only determining propensity for water retention, but also the corrosivity of the environment in the presence of the aqueous medium for the identified critical segment.

This type of system integrates a number of key functionalities, including water-phase behaviour determination, pH computation, corrosion modelling, flow modelling and comprehensive pipeline analyses based on lab and field data. Screenshots of typical results view identifying the critical areas for DG-ICDA and WG-ICDA are shown in Figures 1, 2 and 3.

![Figure 3. WG-ICDA Results Screen showing corrosion at pre-selected assessment sites.](image-url)
Real-time corrosion measurement technology can collect corrosion rate data every minute, and save the data on the device where it will be available for retrieval during operator rounds. If available, this corrosion data could be routed through existing wireless or radio communications as well. Locating the corrosion monitors at key points along a wet gas pipeline can provide continuous reliability information to the operator.

**Conclusion**

The technology described in this article is embodied in a comprehensive pipeline corrosion prediction/monitoring system, Predict-Pipe, which provides a rigorous framework for identifying critical inclination segments in a pipeline that may be affected by internal corrosion, and provide a rationale for implementing a real-time monitoring-based methodology to inspect, monitor and provide remediation as needed. The methodology of the ICDA, powered with advanced flow and corrosion prediction models and best-in-class monitoring solutions provides three significant and concrete benefits to pipeline operators:

1. Ability to perform characterisation of pipelines in terms of potential for corrosion damage and determination of critical locations/pipeline segments that require physical inspection with the use of advanced flow and corrosion prediction models.
2. Ability to assess the health of the entire pipeline by performing inspections on selected critical areas of the pipeline in line with existing NACE standards.
3. Ability to view and assess the status of the critical areas in real-time with the application of monitoring technology coupled with real-time data processing.

The utilisation of the ICDA framework empowered with advanced flow models and corrosion prediction tools encapsulates industry leading technology and proven modelling and monitoring systems. It provides pipeline operators compelling cost and safety benefits, such as the ability to easily identify critical areas, proactively prevent corrosion failures and develop efficient, knowledge-based inspection programs for pipeline condition assessment, and monitoring potential for internal corrosion damage in these critical segments through real-time monitoring.

**References**

1. Pipeline and Hazardous Materials Safety Administration (PHMSA) – Significant Incidents Files, June 2012.
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4. NACE SP0206, “Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)”.