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Selection of Pipeline Flow and Internal Corrosion Models

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Foreword

NACE technical committee reports are intended to convey technical information or state-of-the-art knowledge regarding corrosion. In many cases, they discuss specific applications of corrosion mitigation technology, whether considered successful or not. Statements used to convey this information are factual and are provided to the reader as input and guidance for consideration when applying this technology in the future. However, these statements are not intended to be recommendations for general application of this technology, and must not be construed as such.

The purpose of this report is to assist users in making informed technical decisions regarding flow models used to predict the possible locations of internal corrosion, and corrosion models used to predict the severity of internal corrosion at those locations. This report is intended for pipeline operators, model users, consultants, design engineers, and model developers.

Oil and gas pipelines suffer internal corrosion in locations where water is in contact with the internal surfaces of steel pipelines. NACE internal corrosion direct assessment (ICDA) standards SP0206[1], SP0208[2], SP0110[3] and SP0116[4] provide overall guidelines to assess internal corrosion. According to SP0113[5], the direct assessment (DA) methodology is one of the pipeline integrity assessment techniques for both internal and external corrosion. The DA methodology involves four basic steps: pre-assessment, indirect inspection, detailed examination, and post-assessment. In the ICDA standards, the indirect inspection step involves prediction of locations susceptible to internal corrosion using flow models and prioritization of overall corrosion severity at these locations using corrosion models.

Solid particles affect corrosion in several ways, such as underdeposit, corrosion-erosion, and erosion-corrosion. Some flow models help operators to assess locations where solid particles impinge (causing erosion-corrosion) and accumulate (causing underdeposit corrosion [UDC]).

Flow and corrosion rate prediction models can also be used in conjunction with inline inspection (ILI) data to establish the frequency of ILI runs by predicting the anticipated metal loss. This is applicable to piggable pipelines, for which periodic inspections using ILI tools are typically implemented. The ILI tool travels along the pipeline to directly inspect the defects and imperfections. NACE SP0102[6] provides descriptions of ILI tools.

NACE Task Group (TG) 076, "Oil and Gas Production, Corrosion Prediction: Report," is currently developing a technical report describing various flow and internal corrosion models. Most ICDA standards list several models in their non-mandatory appendices, and allow the users to select appropriate models at their discretion.

Selection of appropriate flow and corrosion models is thus a key step in controlling the internal corrosion process. This report assists the user in selecting the appropriate flow and corrosion models to complement other corrosion control and corrosion assessment processes.

If the assessment processes establish that the internal corrosion rate is high, mitigation strategies are developed to control corrosion. NACE SP0106[7] provides methodologies to control internal corrosion of pipelines.

This report was prepared by TG 447, "State-of-the-art Report on Flow and Corrosion Models." TG 447 is administered by Specific Technology Group (STG) 35, "Pipelines, Tanks, and Well Casings." This report is issued by NACE International under the auspices of STG 35.

Introduction

Oil and gas pipelines suffer internal corrosion in locations where water is in contact with the internal surfaces of steel pipelines. NACE internal corrosion direct assessment (ICDA) standards SP0206[1], SP0208[2], SP0110[3] and SP0116[4] provide overall guidelines to assess internal corrosion. According to SP0113[5] the direct assessment (DA) methodology is one of the pipeline integrity assessment techniques for both internal and external corrosion. The DA methodology involves four basic steps: pre-assessment, indirect inspection, detailed examination, and post-assessment. In the ICDA standards, the indirect inspection step involves prediction of locations susceptible to internal corrosion using flow models and/or prioritization of overall corrosion severity at these locations using corrosion models. Most ICDA standards list several models for these purposes in their nonmandatory appendixes, and allow the user to select appropriate models at their discretion.

Flow and corrosion rate prediction models can also be used in conjunction with inline inspection (ILI) data to establish the frequency of ILI runs by predicting the anticipated metal loss. This is applicable to piggable pipelines, for which periodic inspections using ILI tools are typically implemented. The ILI tool travels along the pipeline to directly inspect the defects and imperfections. NACE Publication 35100[8] provides descriptions of ILI tools.

This report provides information for operators to assist in assessing the applicability of both proprietary and non-proprietary models, as well as the ability to assess the suitability of these models for a particular application.

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Section 1: General

Primary functions of pipeline corrosion professionals are to evaluate if a given material is susceptible to a particular type of corrosion in a given environment, estimate the rate at which the material corrodes in that given environment, and, as required, to develop mitigation methods to control the corrosion rate in that environment.

This technical committee report addresses metal loss corrosion models of carbon steel. Though there are stainless steel (corrosion resistant alloy [CRA]) pipelines and CRA-clad pipelines, many oil and gas pipelines are constructed using carbon steel. The carbon steel pipelines are susceptible to mass loss corrosion (general and localized), sulfide stress cracking (SSC), hydrogen induced cracking (HIC), and preferential weld corrosion in the presence of the aqueous phase. This technical committee report addresses only metal loss corrosion models of carbon steel.

The corrosiveness of the aqueous phase depends on several parameters including, but not limited to, brine chemistry, flow rate, acid gas content (CO_2, H_2S), O_2, crude oil, liquid hydrocarbons, additives, sand, solids, (including organic deposits and inorganic deposits), microbes, temperature, and pressure. The suitability of carbon steel for the given environment with respect to all types of corrosive species is evaluated.

Based on several years of field experience and laboratory experiments, a number of predictive models have been developed. Many predictive models aid corrosion professionals in making appropriate decisions. In addition, computer technologies has enabled development of user-friendly software for these predictive models. Before using such predictive models, understanding the overall scope of applicability and ability of the different models is advantageous.

The predictive models are used to answer the following questions:
- Does internal corrosion pose a threat?
- Where in the pipeline is the internal corrosion likely to occur?
- When during operation is the internal corrosion likely to occur?
- What is the corrosion mechanism likely to be?
- Which operating parameters need to be monitored to predict the corrosion?

Does internal corrosion pose a threat?
Internal corrosion occurs if water or any other electrolyte (containing CO_2, H_2S, or oxygen) contacts the inner wall of the pipeline. In general, the water content of production pipelines is high and that of transmission pipelines is low (e.g., for oil transmission, pipelines typically carry less than 0.5% volume basic sediment and water [BS&W]).

Where in the pipeline is the internal corrosion likely to occur?
Over a period of time, water and/or solids accumulate in locations such as the low-lying areas, top-of-the-line (TOL), or over-bends, depending on the amounts and characteristics of fluids (oil, gas, and water). Flow models enable prediction of locations where water accumulates to create corrosive conditions and enable prediction of locations where solid particles impinge or where solids (including organic deposits and inorganic deposits) accumulate.

When during operation is the internal corrosion likely to occur?
The pipelines are designed for and operated at particular flow rates. However, the field operating conditions change progressively (because of changes in production), seasonally (e.g., seasonal temperature variation), accidentally (e.g., failure of upstream equipment), or intentionally (e.g., the flow is stopped for maintenance reasons) for various reasons. The models are able to predict corrosion likelihood in various operating conditions, provided those conditions are inputted into the model.

What is the corrosion mechanism likely to be?
Corrosion mechanisms differ depending on various parameters and on whether corrosion manifests as general or localized. Corrosion models can predict general corrosion, localized corrosion, or both. Corrosion models that have been developed to predict localized internal corrosion are more relevant to predict localized corrosion than those models that only predict general corrosion.

Which operating parameters are monitored to predict the corrosion?
Internal corrosion is influenced by several parameters, including material of construction, diameter of the pipeline, orientation (horizontal, vertical, or inclined), flow rates of oil, gas, water, and solid, ratios of oil to water and gas to water, temperature, pressure (total, partial pressure of CO_2, partial pressure of H_2S, oxygen content), compositions of oil (including saturates, aromatic, resins, and asphaltenes [SARA] analysis), gas, and water (including sulfate ions, bicarbonate ions, chloride ions, and acetic acid), and microbial species. Several corrosion models have been developed to predict individual as well as combined effects of these parameters. The parameters relevant to the particular pipeline operating condition are determined and only models dealing with these parameters are used to predict