

Paper No.
16732



Pipeline and Subsea Integrity Assessment Using Corrosion Direct Assessment and Local Area Inspection

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ABSTRACT

In the oil and gas industry, the management of the integrity of all pipelines and associated equipment ensures safe operation and availability for production during their intended life. Pipeline integrity assessment is usually executed in three separate steps:

1. threats (e.g., corrosion) analysis including effectiveness and efficiency of mitigation;
2. verification by monitoring and inspection;
3. fitness for service analysis to determine integrity status, estimate remaining life, and identify required follow up actions.

Typically, in-line inspection by intelligent pigs is used to inspect for corrosion covering the entire pipeline. However, this approach is not always practical for more remote non-piggable pipelines, where verification can be a challenge and monitoring at topsides is often not sufficient to provide reliable data on the corrosion threat and effective mitigation of the full pipeline length. Therefore, alternative approaches are sometimes necessary.

This paper describes a practical engineering approach that leverages the available expertise, consisting of the following steps.

1. This method starts with the corrosion analysis to determine a worst-case scenario of maximum expected wall loss. The analysis uses corrosion prediction software (that includes multiphase flow model, a verified oil-water wetting model) as well as an analysis of the mitigation measures by operations (including corrosion inhibitor injection availability) and the data available that supports the corrosion inhibitor performance. This analysis results in a flow and corrosion profile and identification and prioritization of critical locations for local area inspection. Wall loss at a different scenario with different confidence is also estimated based on both model and data limitations.
2. An inspection plan, including identification of the minimum required scope and inspection method, is developed and implemented. Fitness for purpose analysis is performed based on different limit states.
3. Local inspection results are extrapolated to the whole system using different statistical methods to give an updated corrosion profile. The confidence of the overall integrity assessment is established based on both corrosion confidence and inspection confidence.
4. The inspection results are analyzed, resulting in a pipeline integrity status determination, which includes remaining life/extension and next inspection due date.

A case study illustrates the implementation of the approach for the analysis of multiphase flowlines in the Gulf of Mexico.

Key words: internal corrosion, corrosion modeling, corrosion inhibition, direct assessment, subsea pipeline, local area inspection, pipeline integrity

INTRODUCTION

Assurance of the integrity of pipeline and subsea equipment is becoming increasingly important to the oil and gas production sector. Most of the operators have a pipeline and subsea integrity management system to determine ‘when’ and ‘what’ equipment to inspect or repair. For offshore pipelines, a variety of non-destructive testing (NDT) techniques are typically used to measure how internal corrosion has progressed. In-line inspection by intelligent pigs is the preferred method to inspect for corrosion covering the entire pipeline. However, this approach is not always practical for more remote non-piggable pipelines, where verification can be a challenge and monitoring at topsides is often not sufficient to provide reliable data on the corrosion threat of the full pipeline length. Therefore, alternative approaches are sometimes necessary. A new technology using local area inspection is deployed and used in the pipeline internal inspection. Since it is local area inspection, it is limited to internal corrosion, mostly, CO₂/organic acid corrosion dominant, where a relative uniform corrosion mechanism is applicable. This method is not deemed suitable for localized corrosion (e.g. sour (H₂S) corrosion) where information in one section is not necessarily relevant for the rest of the pipeline.

Corrosion assessment prior to the inspection will play a key role in the identification and prioritization of critical locations for local area inspection. The scope of this paper is to introduce a practical engineering approach that leverages the available expertise on corrosion and its mitigation, inspection, and fitness for service analysis to review the integrity of the pipelines. This approach is applied to both offshore and onshore pipelines.

GENERAL METHODOLOGY

The general methodology for integrity assessment using local area inspection measurements is illustrated in Figure 1

General Methodology

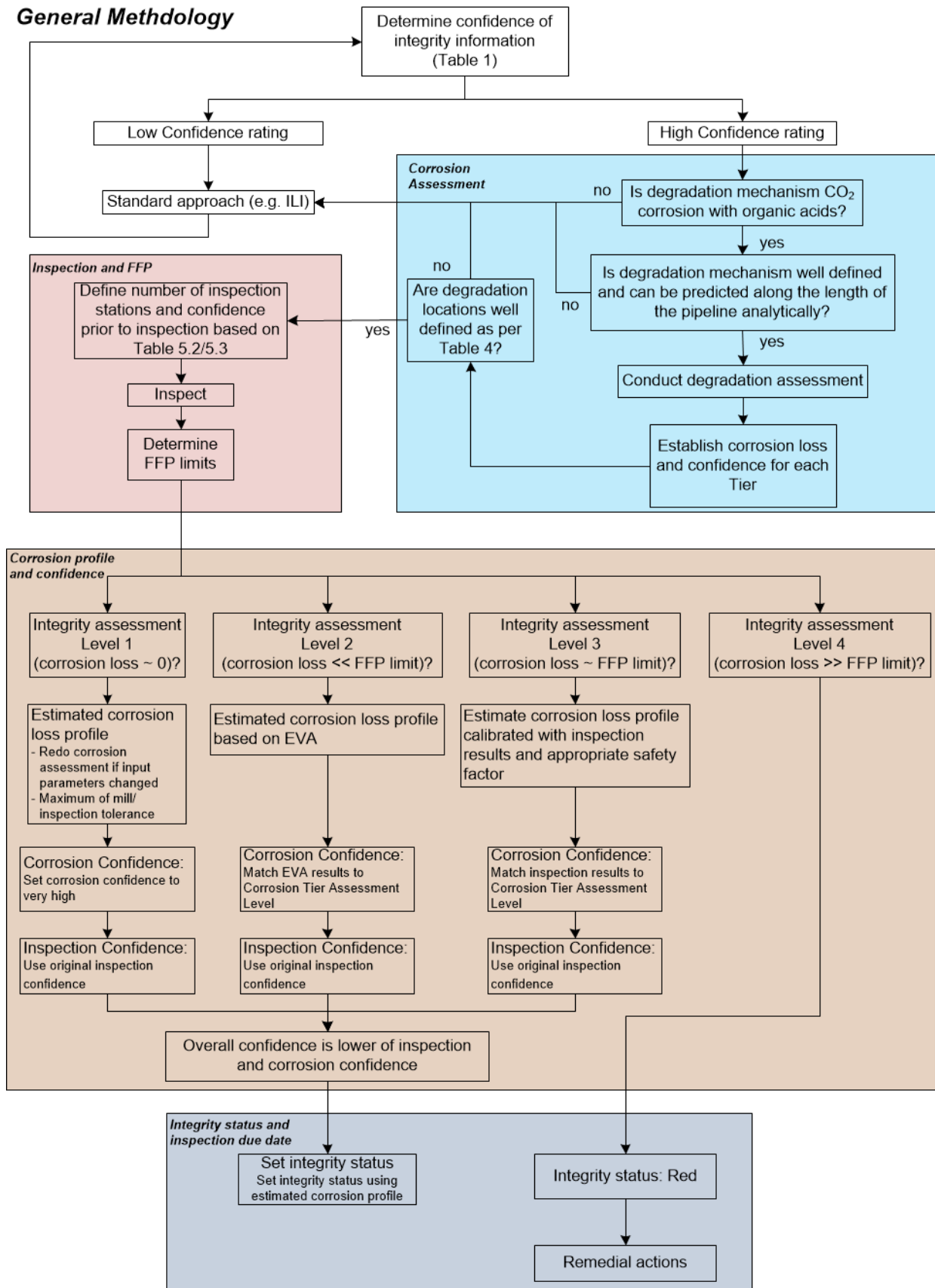


Figure 1: General methodology flowchart for pipeline integrity assessment

The integrity assessment consists of four major elements as follows

- A. Corrosion assessment
 - a. Gather data and perform corrosion analysis
 - b. Part of the degradation assessment should include the effectiveness of mitigation, such as CI testing data, CI availability, and oil-wetting
 - c. Review process data that could impact corrosion as well as its mitigation
 - d. Define the corrosion confidence based upon model uncertainty and the available input data information
- B. Inspection and fitness for purpose (FFP)
 - a. Define the inspection location and the number of inspection stations as a function of corrosion analysis and corrosion confidence in the previous step
 - b. Inspection and perform fitness for purpose analysis
- C. Corrosion profile and overall Integrity assessment confidence.
 - a. Update corrosion profile based upon inspection and/or new data available
 - b. Determine overall integrity assessment confidence based on updated corrosion confidence and inspection confidence
- D. Integrity status and inspection due date

These steps are further described in the following sections. A prior condition for this approach to be applied is to collect the relevant information as per Table 1. A total confidence rating of at least “High” is required to use the approach outlined in Figure 1. If the confidence in the integrity information is less than “High”, then a standard approach is to be followed.

Table 1: Guide to the rating of information confidence rating

Type of information	Information Status
Degradation Assessment	Documented review of expected degradation mechanisms and sufficient design data ¹ to determine available “corrosion tolerance”
	Partial identification of expected degradation mechanisms but sufficient design data to determine available corrosion tolerance ²
	No identification of expected degradation mechanisms and insufficient design data to determine available corrosion tolerance.
Monitoring of relevant operational/process parameters	Reliable and sufficient historical data ³ available to make an assessment of expected degradation.
	Limited historical relevant data with respect to the number of parameters and their historical completeness.
	No monitoring of relevant data.
Control of expected degradation mechanisms	Degradation mechanism has been identified and is stable and controllable ⁴
	Degradation mechanism is either unstable or uncontrollable.
	Degradation mechanism is both unstable and uncontrollable.
Previous Inspections (Irrespective of the inspection results)	Comprehensive and reliable relevant data available from multiple inspections
	Some relevant inspection data available
	No relevant inspection data available

Notes:

1. Sufficient design data means the minimum data to determine corrosion tolerance, e.g., design pressure, design factor, yield strength, ultimate strength
2. Corrosion tolerance is the minimum allowable wall thickness as per the selected defect assessment code, e.g. ASME B31G,¹ DNV RP-F101.²
3. Reliable and sufficient operational data means that the data is of good quality and covers a large majority of the duration of the operating life to date.
4. A mechanism is considered unstable if/when the rates are very high, e.g., brittle fracture, active sulfide stress corrosion cracking. Controllable means either that the mechanism can be avoided or that a low degradation rate can be assured.

CORROSION ASSESSMENT

General

The corrosion assessment approach was in line with previously published work.^{3,4} The corrosion prediction software used as a basis includes multiphase flow modeling, CO₂ and organic acid corrosion model, a verified oil-water wetting model,^{5,6} and an availability related mitigation input. However, in this program, the aim is to go beyond the standardized methods and to leverage the full capability of the engineers involved.

The corrosion prediction tools available is state of the art; however, by its definition, corrosion prediction is not the same as a corrosion review since looking backward is different from looking forward. Corrosion prediction tools are designed to predict unmitigated corrosion, while a corrosion review focuses on the prediction of potential corrosion in a system where the corrosion was mitigated.

When reviewing the integrity, the following aspects are to be included:

1. Predict the potential unmitigated corrosion rate