Vysus Group

Whitepaper

How to manage the integrity of multiphase subsea pipelines without pigging

The Pipeline and Hazardous Materials Safety Administration (PHMSA), estimates that 40% of the world's pipelines are difficult to pig or deemed "unpiggable", which means they cannot be inspected via inline inspection (ILI).

As a pipeline operator, you need to meet strict legislative and environmental requirements. You must demonstrate and document the safe performance of pipeline assets by assessing risk factors, performing inspections, and implementing mitigation measures. But how can you effectively manage the integrity of subsea pipelines without pigging?

Current regulations

Current Pipeline Safety Regulations defined in the US and UK require integrity assessments to be performed for certain onshore pipelines using any of the following methods:

(1) Inline Inspection (ILI).
(2) Pressure Testing.
(3) Direct Assessment (including external wall thickness scans and corrosion assessments).
(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the pipe.

Regulations for offshore pipelines are somewhat less prescriptive with no existing requirements for integrity management. However, ensuring the integrity of offshore pipeline assets is no less important than ensuring the integrity of onshore pipeline assets, therefore the listed methods are equally relevant.

Optimum inspection methodology

The best inspection method is generally an ILI method. Since the implementation of the onshore and offshore pipeline safety regulations in 1996, new tools and technologies have rapidly been developed to make traditionally "unpiggable" pipelines piggable. This is done, at least partially, through the use of tethered pigs, robotic pigs, or specially designed pigs that can manoeuvre the tight bends which older generation pigs could not navigate.

40%

PHMSA, estimates that 40% of the world's pipelines are difficult to pig or deemed "unpiggable", which means they cannot be inspected via inline inspection (ILI).

Despite these advances in technology, a large percentage of pipelines remain difficult to pig. This is partly related to the use of unbonded flexible pipes for the majority of some pipelines which renders the use of ILI ineffective. This is because the technology has not evolved to a sufficient standard to be effective at inspecting these types of pipes.

However, there are various reasons why pigging would not be required to be conducted, or feasible, on a pipeline including:

- No pig trap (and impossible, or not economically viable, to install temporary one).
- No return line (and impossible, or not economically viable, to install subsea receiver).
- Too many changes in ID (therefore the sealing for propulsion would be ineffective).
- Bends too tight in line (would cause pig to get stuck).
- Un-barred Tees in line (would cause pig to get stuck).
- Insufficient pressure rating of line to propel pig through and out of the line.
- Too much build-up of wax or scale which cannot be removed through cleaning pig runs.
- Stuck valves.
- High confidence that there's no internal corrosion and line is in good condition.

Subsea Inspection Tools Available

Table 1 summarises various subsea inspection tools available. The information in the table should only be used as a guide. Test capabilities, inspection ranges and data collection speeds are rapidly changing as new developments are put into practice. The capabilities offered by one company may be significantly inferior to those offered by another for the same test.

The speed of system deployment and data collection may play a significant part in technique selection.

Table 1 – Subsea Inspection Methods

Techniques	Surface Preparation	Inspection Range	Coverage	Limitations
Computed Tomography (CT)	None or minimal cleaning required	10 - 80 mm	360˚ x ~20mm (dependent on pipe diameter)	Provide general wall loss information. Circumferential access to pipe requires dredging. Very slow due to small scan width. Quantitative.
Ultrasonic Guided Wave (UGW)	Preparation required only at the probe band location.	5 mm and up	Selected areas or 360˚	
Electro Magnetic Acoustic Transducer (EMAT)	Minimal surface cleaning	5 mm and up	360˚ x ~20mm (dependent on pipe diameter)	Wall loss areas smaller than the probe's footprint will be underestimated.
Pulsed Eddy Current (PEC)	None required Can inspect through 200mm of corrosion and concrete weight coating	Larger length than the spot or automated UT	Selected area or 360˚	Wall loss areas smaller than the probe's footprint will be underestimated. Isolated pits or smaller diameter holes cannot be detected. Provides an average material thickness of area under probe.
Time of Flight Diffraction (TOFD)	High quality cleaning over all of test area	Limited by size of scan frame.	Selected areas or 360˚	Typically limited to the inspection of welds.
Corrosion mapping (CMUT)	High quality cleaning over all of test area	Limited by size of scan frame. Typically ~ 1m	Selected area or 360˚	Capable of providing accurate remaining wall thickness. Slow data acquisition.
Corrosion mapping Phased Array (CMPAUT)	High quality cleaning over all of test area	Limited by size of scan frame. Typically ~ 1m	Each scan line ~ 6 0 mm wide. Selected area or 360˚	
Digital Radiography (DRT)	None or minimal cleaning required	Area dictated by size of data recorder plate	Selected area	
Alternating Field Current Measurement (ACFM)	Minimal cleaning required	Limited by size of scan frame.	Selected length or 360˚	Typically used for the detection of fatigue cracks at the toes of welds.
Saturated Low Frequency Eddy Current (SLOFEC)	Minimal, can test through ~ 20 mm coatings	Limited by umbilical length	Typical 50% pipe diameter per scan	

Negatives of pressure testing

Carrying out pressure tests to verify pipeline integrity has its own disadvantages. Specifically, they do not identify the severity of flaws (other than critical flaws that result in failure), or their locations. In some cases, as a result of the pressure tests themselves, existing flaws can increase in size. Pressure tests require pipelines to be taken out of service, which can be logistically challenging and also extremely costly.

Verifying pipeline integrity

Direct assessment is therefore often seen as the best option to verify pipeline integrity, although this is not without its challenges due to the difficulty of accessing subsea pipelines and the limitations in available technology to perform subsea wall thickness inspections. Consequently, the industry has started to look at methods such as flow simulations, corrosion assessments, and application of statistical analysis to determine locations where the highest internal corrosion rates are expected. This helps to identify optimum locations for subsea inspection of the difficult, or impossible, to pig pipelines. Remotely operated vehicles (ROV) are also being deployed in subsea non-destructive testing (NDT) applications which use digital radiography, computed tomography, UT and even ‘pulsed eddy current’ techniques where measurements are taken through any non-conductive material such as insulation, protective coatings, concrete and marine growth and these are already being used with considerable success in the market.

Case Study

The following case examples are of a subsea pipeline layout which would not be subjected to pigging operations.

Layout

Figure 1 shows three production wells connected to a manifold via jumpers then a flowline, covering most of the distance, to a riser base then a riser up to the FPSO. The jumpers are unbonded flexible pipes like the riser therefore no information can be gathered for them through ILI. The flowline is carbon steel and perceived to be a weak point compared to the corrosion resistant alloys (CRA) of the flexibles, manifold and riser base. As such the following examples will focus on assessment of the carbon steel pipeline.

Management approach

The typical approach to integrity management would involve the risk assessment process identifying the threats to the pipeline system along with what can be used to assess these threats. The outcome of this is a list of KPIs for internal threats, linked to individual degradation mechanisms, which can be directly monitored from the pipeline contents. Depending on the

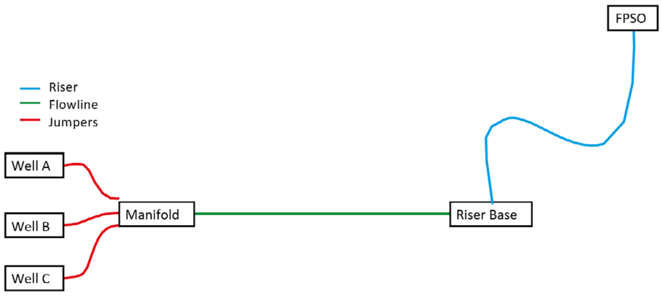

Figure 1 – Typical subsea layout Integrity

results of these monitoring measures, the internal condition of the pipeline can be gauged.

The fluids in the line are multiphase production fluids and the fluid parameters monitored are:

- Temperature
- Pressure
- CO_2 content
- H_2S content
- Sand (production rate and particle size)
- Bacterial monitoring (sessile and planktonic)
- Flowrate (for each phase)
- Gas/Oil Ratio (GOR)
- Water cut
- Produced water chemistry (ion analysis)
- Injected chemicals (dosage and availability)
- Corrosion inhibitor
- Biocide
- Wax inhibitor
- Scale inhibitor
- Methanol

In addition to fluid parameters there are metallic coupons which are commonly used to expose a small sample of material to the fluid flow within the pipeline. The material used for these coupons is selected to be as similar to the pipeline material as possible in terms of corrosion resistance, as the pipeline component they are intended to monitor. They can be retrieved and assessed for internal corrosion of the pipeline and swabbed in order to obtain samples for sessile bacteria monitoring.

However, all threats cannot be covered from the above-mentioned monitoring data, keeping in mind that also, all threats cannot be covered by ILI such as crevice corrosion. Sometimes, the ideal monitoring method for particular threats is not available from the concerned asset.

Similarly, external visual inspections can cover some threats but there will be some threats un-assessable, such as dents at six o’clock, these are termed accepted threats and would be detectable by ILI as well as external wall thickness scanning. This depends on the type of external protection the pipeline has, e.g. if concrete coated or buried then there is very little information available from external inspection.

Case example A – Good monitoring results; no need for external wall thickness measurements.

In an ideal case where all of the parameters monitored are readily available since the pipeline came into operation. The values returned did not raise integrity concerns, so there would be high confidence that no internal corrosion was taking place within the pipeline. Therefore, there is no need for conducting external wall thickness inspections.

Case example B – Insufficient/ unfavourable monitoring data: requires external inspections.

In this case some of the monitored data is not available and what is being retrieved indicates that corrosion could be taking place. The gas analysis is offline so there is no CO2 or H2S concentration data available and it has been offline for two years. It is known that the corrosion inhibitor injection has been intermittently off-specification available for a two-year period. Additionally, retrieved metallic coupons have reported moderate to high levels of corrosion taking place.

Corrosion assessments as per industry standards such as NORSOK, M506, NACE M0175/ ISO 15156, DNV-RP-O501 & API 581 may be performed in order to identify the most susceptible locations and estimate wall loss at such sites, using conservative assumptions to account for any gaps in the required input data. Such an analysis is typically performed at incremental conditions caused by, or resulting from, changes in pressure and temperature with distance. Whilst corrosion assessments provide a useful basis for understanding a pipeline's integrity, their accuracy is affected by the quality - or limited availability - of input data, the conservative nature of the corrosion models used and the potential for localised abnormalities which can lead to unpredictable rates of degradation (e.g. heavy deposition of solids, weld defects and abnormal flow effects, etc.) For this reason it is best practice to validate such assessments with external inspection at a sample of locations identified as being the most susceptible.

One of the major drawbacks with external wall thickness scanning is the requirement to target specific locations for analysis. Whilst they are often suitable for validating damage mechanisms resulting in general wall loss, it is unlikely that they would be able to identify regions of isolated or localised attack unless extensive coverage is selected; in such cases, the external checks might give a false assurance of a pipeline's integrity. However, any

sites of significant degradation that are discovered by this method can provide the justification to validate high level actions such as shutting a pipeline in or replacing it.

Case example C – Significant degradation known to have taken place. Suggest replacement of line or decommissioning of wells & pipeline system.

In this case the data suggests that the pipeline will have been severely corroded. Even without external wall thickness checks there is enough confidence in the monitoring data and corrosion assessments to consider that failure is imminent. This decision might be reached if good quality and comprehensive monitoring data has been supplied and if predicted corrosion rates correspond with secondary validation methods such as topsides external wall thickness measurements or weight loss trends of in-line corrosion coupons. In such a circumstance, the activity of performing subsea wall thickness checks could be considered an inadequate means of integrity assessment or simply a poor use of resource and expenditure. In this case the pipeline should be shut down and either replaced or the wells and pipeline decommissioned.

Conclusion

The assessment of unpiggable pipelines, and the decision of whether or not, and how, to conduct external wall thickness checks, depends on the available data of how the pipeline has been operated. Lack of information, or information indicating moderate to significant corrosion has taken place, drives the requirement to further investigate the condition by conducting external wall thickness checks. Ultimately, investing a little up front on monitoring and mitigation measures could save you significant cost in the longer term by not having to perform these often-costly inspections.

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