‘Optimisation of Pipeline Integrity Management Activities’ Q&A

Thank you to everyone who registered and joined us for our webinar entitled ‘*Optimisation of Pipeline Integrity Management Activities*’.

Our presenter, Jonathon Doyle, has answered your questions that were submitted during the webinar.

If you do have anything further that you would like to ask our presenters, please contact Jonathon directly.

Jonathon Doyle, Senior Integrity Engineer

Email: j.doyle@penspen.com

Questions and Answers

Q: What are the published guidelines and RP for typical inspection frequencies? Can you please give some examples of guidance and publications?

A: As examples, ASME B31.8S provides prescriptive guidance for In-Line Inspection (ILI). IGEM TD/1 provides general guidance for ILI, Vantage Point Surveys (VPS) and aerial surveillance. API 570 also provides guidance for inspection of piping systems.

Conforming to these guidelines can be considered good practice. Performing inspections at differing frequencies, or performing alternative activities, is likely to require demonstration that the risk remains acceptable.

Q: In the case of risk, what would be a good indicator of control, in your experience?

A: Quantifying the risk reduction achieved by individual mitigation measures is a challenge. In the first instance, this can be considered qualitatively, with an initial risk assessment being performed to determine the ‘raw’ risk and re-assessing the mitigated risk with controls in place.

Implementation of inspection and other integrity activities as outlined in published guidance can be considered good practice and is typically sufficient to demonstrate that risk is managed at a tolerable level. Risk assessment methods such as bowtie allow for visualisation of the barriers in place, to control both the likelihood of an incident and the consequence of failure occurring.

Quantitative risk assessment (QRA) can be performed to compute the probability of failure and the consequence of failure. In the UK, guidance for pipeline QRA is provided in IGEM TD/1 and TD/2, BS PD 8010-1 and in documents published by the Health and Safety Executive (HSE). There is also published guidance for performing Cost-Benefit Analysis (CBA) to determine whether implementing additional mitigation provides sufficient risk reduction to justify the expenditure. Proprietary software is also available for conducting these assessments.

Q: What baseline of event types is applied when considering pipeline failure modes?

A: Typically, we will consider leak and/or rupture scenarios, as these carry the most significant potential consequence to people and the environment. However, other failures, such as blockage or loss of operability, may be considered.

The failure modes will depend on the pipeline and will vary based on design, location, type of product conveyed, operating parameters, etc. Risk assessment methods such as FMEA and FMECA can be applied to identify credible failure modes. Published guidance documents, such as API 1160 and BS PD 8010-4, provide guidance on credible integrity hazards.

Q: What is the number of pipeline inspections surveys that Penspen has undertaken in the last year?

A: Penspen's Asset Management business stream holds a number of Operations and Maintenance (O&M) contracts with pipeline operators in the UK, the US and Latin America. Through these contracts, we routinely perform inspection and monitoring activities, such as VPS, line walks, depth of burial surveys, ON- and OFF-potential cathodic protection surveys, AC corrosion surveys, Close Interval Potential Surveys (CIPS) and Direct Current Voltage Gradient (DCVG) surveys.

Penspen also supports a number of operators with their ILI campaigns, performing piggability studies, assisting with tendering (or sub-contracting ILI services on behalf of the operator), and providing programme management services. We provide these services to several operators per year, depending on the requirement for performing ILI.

Historically, Penspen has also supported offshore pipeline operators with the development of scopes of work, supporting technical review of tenders. We have also provided client representatives on board survey vessels, to perform preliminary assessment of inspection findings and ensure the survey contractor fulfils the technical requirements of the survey.

Q: What are your advancements in non-piggable pipelines, lined pipelines and other types of pipelines with very limited access to inspection and assessment?

A: Penspen is not an inspection vendor but is able to provide consultancy services to pipeline operators, to assist in the identification of suitable inspection solutions and in the execution of inspection activities.

We have performed a large number of piggability studies for a range of pipeline operators, and conducted market research for clients, to determine potential inspection solutions.

As owner and operator of a section of the Manchester Jetline, Penspen is a member of both the Pipeline Operators Forum (POF) and the UK Onshore Pipeline Operators Association (UKOPA), through which it is able to remain up to date with the latest industry developments and best practice. This includes involvement in the production of UK good practice guides.

Penspen has recently been involved in Joint Industry Projects (JIPs), focusing on non-intrusive inspection techniques and the evaluation and assessment of circumferential cracks in ageing pipelines.

Q: In your point of view, what alternative options exist?

A: Integrity management is an holistic concept that extends throughout the asset lifecycle. Therefore, consideration of how risk and integrity will be managed during operation should be made during initial design. If it is known in initial stages that inspection will not be possible, then the pipeline design can account for this limitation and provide additional mitigations to ensure the pipeline will remain fit for the intended service life. Penspen has recently been involved in performing risk assessment at FEED stage to support the technical justification for deferral of ILI for a proposed subsea pipeline.

Increasingly, there is an expectation from regulators that pipelines should be piggable (in the UK, PSR Regulation 7 states that "*the operator shall ensure that no fluid is conveyed in a pipeline unless it has been so designed that, so far as is reasonably practicable, it may be examined and work of maintenance may be carried out safely*"). However, there are a number of reasons why a pipeline can't be internally inspected. Alternatives to ILI include direct assessment. Guidance for the Internal Corrosion Direct Assessment (ICDA) and the External Corrosion Direct Assessment (ECDA) is provided by NACE. There are a number of non-intrusive inspection technologies for external inspection of internal pipe condition.

Monitoring of product composition and operating parameters provides information that may inform risk assessment and determine whether hazards are active. Corrosion inhibition, as well as other inhibition regimes to prevent waxing, hydrate blockages, etc., can be implemented. Modelling using this acquired data can identify whether a particular hazard may manifest and where the risk may be highest. Other monitoring systems, such as leak detection for onshore pipelines and tracking of vessel movements in the vicinity of subsea infrastructure, may be implemented to help reduce risk.

More complex, quantitative risk assessment and cost-benefit analysis may be employed to demonstrate that the reduction in risk from inspection is grossly disproportionate to the time, cost and/or technical complexity of enacting the inspection activity. Therefore, this can confirm that risk is managed to ALARP (as low as reasonably practicable).

Q: For the risk assessment of offshore pipelines, are there different threats that need to be considered from onshore pipelines?

A: In terms of the failure mechanisms, these are generally similar. For example, internal and external corrosion can manifest on both onshore and offshore lines, as can the impact from third party interference. However, the failure modes will differ. E.g. impact damage onshore may be from third party works in the vicinity of the pipeline route and offshore impact may be from trawling or anchor drags. The likelihood and consequence of these hazards will therefore vary, even if the failure mechanisms are the same.

Published documents for pipeline integrity management, such as API 1160, ASME B31.8S and BS PD 8010-4, provide guidance on typical pipeline integrity hazards. The majority of hazards identified apply to both onshore and offshore pipelines. DNGL-RP-F116 and the Energy Institute guidelines for the management of integrity of subsea facilities provide a list of integrity hazards for offshore pipelines, but, in general, these align with the hazards identified in the other published guidance documents.

Q: How are the changes in soil properties and time (i.e. in detail engineering and mid-life/end life, or at time of risk analysis) accounted for in pipeline Risk Based Inspection (RBI)?

A: Typically, it would not be expected that the physical properties of the soil around the pipeline would change with time. However, changing water tables and seasonal differences can impact on pipeline integrity and should be adequately addressed in design and managed during operation.

Soil properties may vary along a pipeline route and this should be considered in design, to ensure suitable materials are selected, appropriate coatings are specified and the cathodic protection system design takes cognisance of these differences, etc.

The depth of cover over a pipeline may increase or decrease over time due to erosion and deposition, and potentially by mechanical means. The direct (e.g. soil overburden) and indirect (e.g. reduced cover provides less resistance to impact damage) impacts of this on the pipeline should be considered, and appropriate inspection/survey performed. The findings should then be fed back into the risk assessment to inform future risk and inspection requirements.

Ground movement due to landslip etc. may also be a credible threat to some pipelines in various oil and gas regions around the world. Monitoring for signs of pipe movement via external line walk surveys (for onshore pipelines), repeat bathymetric surveys (for offshore pipelines), and by internal inspection, will provide evidence of whether the hazard is credible and active. ILI tools are capable of measuring pipe curvature and strain, to allow for assessment of the loads on a pipeline. In areas where there is significant risk of landslip, wider monitoring systems can be put in place to identify signs of large ground movements that could impinge on a buried pipeline.

Q: How does reliability analysis plays role in pipeline RBI analysis?

A: Reliability in terms of Reliability Centred Maintenance (RCM) is not typically undertaken for pipelines, given they are static pieces of equipment. However, it is an important tool for assessment of ancillary pipeline equipment.

Structural Reliability Analysis (SRA) is a form of quantitative risk assessment and involves the use of probabilistic variables to model the probability of failure. SRA is complex and requires suitable data to input to the analysis, and competent risk engineers to perform the assessment. It is not performed routinely, given the time and cost constraints, and the requirement for significant amounts of data.

However, it can be performed to provide input to strategies for inspection, monitoring and rehabilitation of pipelines. The most common application is for corroded pipelines, where large amounts of data may be acquired from repeat ILI. However, sufficient pipe and materials data and operating data is also required to perform a robust assessment.

Q: What are the key difference between optimisation in onshore and offshore pipeline integrity management activities?

A: In general, the process of risk assessment and optimisation of integrity management activities is the same for both onshore and offshore pipelines. The differences arise in the way different hazards may manifest in onshore and offshore pipelines, and the different inspection and integrity management activities that can be employed in the two environments.

Q: Is this method also applicable for subsea cables/flexibles/umbilicals?

A: The general risk assessment methodology is sufficiently flexible and has been adopted for other assets. However, the criteria for what constitutes a tolerable risk will vary and, likewise, the consequences of asset failure will differ. The availability of data for input to the assessment may also vary. However, again, the methodology is flexible enough to allow for increased engineering judgement where data is limited.

Q: If we have two lines of typical gas offshore subsea pipeline, could we assume the integrity result of one aligns to the other?

A: It may be possible to infer some understanding of pipe condition from another pipeline subject to the same conditions. However, there would be less confidence in these findings than if they were acquired directly from the asset.

One example would be the use of ILI findings from a trunkline to infer internal condition of flowlines conveying the same product. In addition to the ILI findings, consideration would need to be given to any differences between the pipelines, differences in operation (e.g. pressure, temperature, flow rate), and any localised issues (such as bends, low points, etc.) where internal corrosion mechanisms may be more significant.