Oil Pipeline Testing Methods

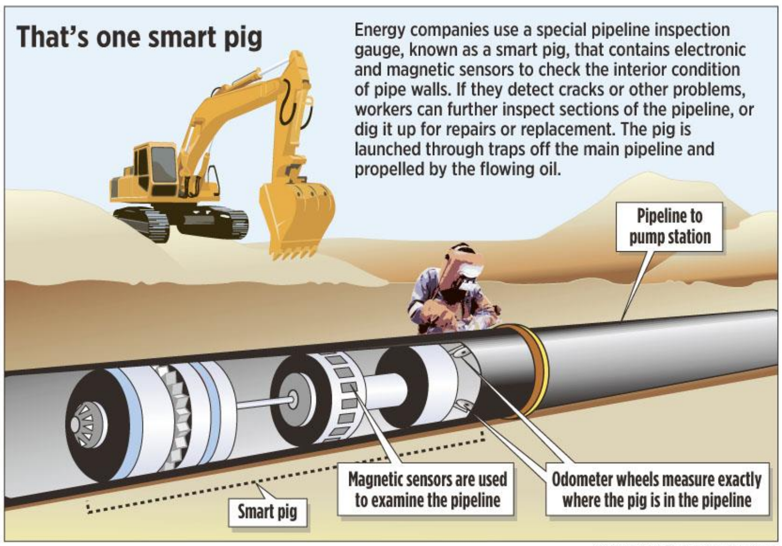
Federal minimum pipeline safety regulations that establish minimum requirements for liquid pipeline safety integrity management allow four approaches to assess pipeline integrity: 1) Inline inspection or "ILI," often called smart pigging, 2) hydrotesting, 3) direct assesment for external corrosion, and 4) an equilavelent other technology that must be noticed and demonstrated to PHMSA before it is used for a particular threat on a pipeline segment. Federal regulation establishes a maximum reassessment period of no longer than 5 years, not to exceed 68 months. The federal regulations are mute as to the various strengths and weaknesses of the four allowed above assessment approaches, but place the obligation on the pipeline operator to know and select which inspection method(s) best matches the threats on a specific pipeline segment, and the need for more frequency reassessments using these permitted assessment methods. There is also no restriction on a pipeline operator from exceeding the above minumum pipeline safety regulations. For example, just running ILI inspection that is not reliable for a particular threat of concern on a pipeline more often, is a violation of federal regulation that produces an illusion that a pipeline segment is more safe or in compliance with federal minimum regulations. When in reality the pipeline segment is actually less safe, given the weakness that can be associated with a particular assessment approach such as the misuse of ILI tools. The following is a brief perspective of the above assessment methods:

I. In-Line Inspection Technology or "Smart Pigging"

Smart Pigging is the practice of using devices known as ILI tools or smart pigs to perform various periodic maintenance inspections usually on a flowing or operating pipeline. Smart pigs are often long, multi-ton, complex devices consisting of at least four main parts; 1) a sensor section designed to possibly identify specific threats the pig is intended to identify such as corrosion, 2) a battery power source, 3) a data gathering/storage segment, and 4) a driver segment, usually using the flowing pipeline fluid to move the pig along the main pipeline. As electronic technology has improved the smart pigs have tended to be asked to do more data gathering and improve efficiency. Because of their length, complexity, and diameter, not all pipelines can successfully handle an ILI pig. Over the past decades many pipelines have been installed to handle such important tools.

As discussed further, ILI tools are usually designed for various types of specific pipeline threats such as corrosion (corrosion ILIs), certain types of some cracks (crack ILIs tools), and some abnormal damage/mapping/caliper (mapping/caliper/geo ILI tools). It is important to recognize that each ILI tool approach has at least two important "tolerance" specifications; 1) the ability of the ILI tools to identify a specific type of threat, and then the ability to identify the threat in such a manner so as to permit an evaluation of the strength of the remaining pipe. Such tool tolerences are called the Probability of Detection, or POD, and the Probability of Identification, or POI, respectively. POD is the probability that the ILI tool will be able to detect a certain feature while POI is the probability that once a certain feature is detected will be correctly identified (such as to size depth etc). These tool tolerences vary widely depending on the type of threat, the ILI tool's design/sensors, and sometimes the pipe and and the location of the anomaly such as near pipe welds. No ILI inpection tool currently has the ability of 100% POD or POI. Tool tolerances are not always accurate, so pipeline operators should perform timely field verification digs to verify ILI vendor claims on their ILI tools and prority software algorithms to asure the ILI tools have not missed a critical anomaly. Field verification of ILI tool's performance is a pipeline operator obligation, not the ILI vendor. Depending on the ILI tools actual tolerences in the field, ILI inspections can tell the operator more about the condition of the pipeline then say hydrotesting which is better suited toward assessing certain types of anomalies (i.e. cracks). ILI inspection, while not cheap, also tend to be cheaper than hydrotesting. It is however very important that for a specific pipeline ILI claimed tool tolerences for various types of anomalies be field verified, especially if identified anomalies are close to critical failure size.

Smart pigs are inserted into the pipeline at various locations, such as a valve or pump station, that has a special configuration of pipes and valves where the ILI tool can be loaded into a pig launcher, the launcher can be closed and sealed, and the flow of the pipeline product then directed to launch the ILI tool into the main line of the pipeline. A similar setup is located downstream, where the tool is directed out of the main line into a receiver, which removes the ILI tool , to allow the gathered, recorded, and stored data to be retrieved for first a preliminary onsite field analysis to verify the quality/success of the ILI tool run, and then a much more detailed offsite analysis performed by the ILI vendor using proprietary software who then issues a subsequent vendor report. Many ILI vendors have procedures that alert the pipeline operator of critical threat anomalies identifed by the ILI tool well before a Final Report is issued. (See Diagram Below)



STAFF GRAPHIC | MICHAEL FISHER

There are several categories or types of smart pigs:

1. **Magnetic Flux Tools:** There are two types of tools commonly used for inspections of hazardous liquid pipelines based on magnetic flux measurements. This technical approach was historically initiated over 40 years ago to help identify general corrosion.

   A) A Magnetic Flux Leakage (MFL) tool, either a low resolution or a more expensive high resolution device containing more sensors, is an electronic tool that identifies and measures metal loss (general corrosion, certain gouges, etc.) through the use of a temporarily applied magnetic field in the axial or direction of pipeline flow. As it passes through the pipe this tool induces a magnetic flux into the pipe wall between the north and south magnetic poles of onboard magnets. A homogeneous steel wall – one without defects – creates a homogeneous distribution of magnetic flux. Anomalies (i.e., metal loss (or gain) associated with the steel wall) result in a change in distribution of the magnetic flux, which, in a magnetically saturated pipe wall, leaks out of the pipe wall. Sensors onboard the tool detects and measures the amount and distribution of the flux leakage. The flux leakage signals are processed, and resulting data is stored onboard the MFL tool for later analysis and reporting. Advances in sensor design and especially in software analysis algorithms have especially occurred in the last several decades advancing analysis especially for the high resolution ILI tools to distinguish between **<u>certain</u>** types of external or internal pipe corrosion with a high degree of reliability, well before such general corrosion threats can advance to pipe failure.

   B) A Transverse MFL/Transverse Flux Inspection tool (TFI) identifies and measures metal loss through the use of a temporarily-applied magnetic field that is oriented circumferentially, wrapping completely around the circumference of the pipe. It uses the same principal as other MFL tools except that the orientation of the magnetic field is different (turned 90 degrees) and this different magnetic field alignment creates some highly complex challenges to both reliable detect and identify such imperfections. The TFI tool is used to determine the location and extent of longitudinally oriented (axial) cracking corrosion. This makes TFI useful for detecting seam-related corrosion. Cracks and other defects can be detected also, though not with the same level of reliability as such determination has proven to be extremely challenging with this ILI approach. A TFI tool may be able to detect axial pipe wall defects – such as cracks, lack of fusion in the longitudinal weld seam, and stress corrosion cracking – that are not detectable with conventional MFL.

2. **Ultrasonic Tools**: There are two types of tools commonly used for inspections of hazardous liquid pipelines based on ultrasonic measurements.

   A) Compression Wave Ultrasonic Testing (UT) tools measure pipe wall thickness and metal loss. The first commercial application of UT technology in ILI tools used compression waves. These tools are equipped with transducers that emit ultrasonic signals perpendicular to the surface of the pipe. An echo is received from both the internal and external surfaces of the pipe and, by timing these return signals and comparing them to the speed of ultrasound in pipe steel, the wall thickness as well as whether the corrosion is external and/or internal can be directly determined. Of particular importance to successful deployment of a UT tool is pipe cleanliness, specifically the removal of paraffin build-up within the pipe. This is especially important for crude oil lines. The use of a cleaning pig is recommended prior to use of UT tools.

   B) Shear Wave Ultrasonic Testing (also known as Circumferential Ultrasonic Testing, or C-UT) is the nondestructive examination technique that more reliably detects longitudinal cracks, longitudinal weld defects, and crack-like defects (such as stress corrosion cracking). Because most crack-like defects are perpendicular to the main stress component (i.e., the hoop stress), UT pulses are injected in a circumferential direction at an angle to obtain maximum acoustic response. Shear Wave UT is categorized as a liquid coupled tool. It uses shear waves generated in the pipe wall by the angular transmission of UT pulses through a liquid coupling medium (oil, water, etc.). The angle of incidence is adjusted such that a propagation angle of usually 45 degrees is obtained in pipeline steel. This technique is appropriate for longitudinal crack inspection though there has been mixed success in its application as the algorithms utilized to analyze the greater volume of data gathered are more complex than compression wave ultrasonic tools though the ultrasonic approaches have the advantage of being more direct measurement devices.

3) **Caliper/mapping/geo tools** are a general family of ILI tools, depending on their sensor design, utilized to determine the location and roundness of the pipe. Those tools are often utilized to determine the damage to the pipeline from possible third party damage or earth movement that might result in pipeline failure such as wrinkles or dents in certain portions of a pipeline.

II. Hydrostatic Testing

Hydrostatic pressure testing is generally used for the post-construction testing of hazardous liquid pipelines and higher stress natural gas pipelines. In a pressure test, a test medium (water) inside the pipeline is pressurized by the use of specialized pumps to raise the test pressure with water to a level that is greater than the maximum operating pressure of the pipeline. This test pressure is held for a number of hours to ensure there are no leaks in the pipeline. Any indication of leakage requires the identification and repair of the leak. The pipeline is then re-pressurized and the test is repeated. The operational integrity at the time of the hydrotest of field welds and more importantly of the pipe itself is assured if the pressure test is successfully completed.

Hydrostatic testing is also widely used to periodically reassess the integrity of hazardous liquid and gas transmission pipelines (particularly when the use of "smart pigs" is not feasible nor appropriate given the state of developing ILI technology). New pipe hydrotesting protocols defined in current minimum federal pipeline safety regulations are not integrity management tests for cracks as has clearly been demonstrated in many recent pipeline crack ruptures. In pipeline reassessments using hydrotesting, the hydrocarbon products are displaced from the section or sections being tested and replaced with water in order to minimize test failure danger and environmental damage that might result from leaks or ruptures.

If a pipeline successfully passes a hydrostatic pressure test, it can be assumed that no hazardous defects are present in the tested pipe at the time of the hydrotest. This is especially important when dealing with pipe sections susceptible to crack threats such as stress corrosion cracking or SCC, or cracking threats that were manufactured prior to approximately 1970 using low-frequency electric resistance welding (LFERW) and lap welding (LW) of the longitudinal seam. Experience has shown that, in some instances, depending on the operation, some of the seam crack threat pipe can be susceptible to rupture failure.

Under federal pipeline safety regulations (Subpart E of 49CFR§195), hydrostatic testing of hazardous liquid pipelines requires testing to at least 125% of the maximum operating pressure (MOP), for at least 4 continuous hours, and an additional 4 hours at a pressure of at least 110% of MOP if the piping is not visible. While not currently defined in minimum pipeline federal regulation, if there is concern with latent cracks that might grow due to a phenomenon known as "pressure reversals", then a "spike" test at the maximum pressure of 139% of MOP for a short period (~1/2 hour) may be conducted. The spike test will serve to "clear" any cracks that might otherwise grow during pressure reductions after the hydrostatic test or as a result of operational pressure cycles in the near term. Studies have been performed that demonstrate the acceptability of the pipeline for extended service after a proper spike hydrostatic pressure test, if there are no factors present that would accelerate crack growth such as corrosion or aggressive pressure cycles. While not required in federal regulations, the hydrotest pressures should also define the test minimum and maximum pressure ranges in a parameter utilized for fracture mechanic assessment, test pressures as a percent of specified minimum yield strength, or %SMYS, s steel property defined in federal pipeline safety regulation.

III. Direct Assessment for External Corrosion

In limited instances where only external corrosion is a threat to pipeline integrity on a pipeline segment, a process called "direct assessment"—an inferential method of evaluating the integrity of a pipeline, may be used in such limited situations. In Direct Assessment, various indirect measurement tools are used to determine locations on the pipeline that may require, in the judgment of the pipeline operator, direct examination to verify pipeline integrity. These locations are then excavated and examined to verify that the pipe is in good condition or to make necessary repairs. The weakness of Direct Assessment is that not all parts or a pipeline segment are actually evaluated, but only segments assumed by the operator to represent a full pipeline segment which can introduce a great deal of error in missing at risk corrosion anomalies. This is one reason that Direct Assessment under U.S. minimum federal pipeline regulations is allowed only for possible external corrosion in integrity management regulations intended to protect high consequence areas.

IV. Other Technologies

In order to encourage the advancement of assessment technologies federal pipeline safety regulations permit pipeline operators to propose Other Technologies to assess pipelines in sensitive high consequence areas. The pipeline operator must, however, demonstrate to PHMSA **<u>before the use</u>** of such Other Technologies that "the operator demonstrates can provide an equivalent understanding of the condition of the line pipe." The burden of proof is on the pipeline operator before they choses to try to utilize such Other Technologies in the field. There are a series of required steps required to demonstrate this other approach to the regulatory agency.