www.pipelinepub.com
Volume 18, Issue 9

Protecting a Precious Resource

By: Trent Ackhurst

Water covers 70 percent of our planet, and it is easy to think that it will always be abundant. However, freshwater—what we drink, bathe in, and irrigate our farm fields with—is incredibly rare. Only three percent of the world's water is freshwater, and two-thirds of that is tucked away in frozen glaciers or otherwise inaccessible for our use. We have witnessed firsthand that many of our water systems are incredibly stressed, with rivers, lakes, and aquifers drying up or becoming too polluted to use.

Recognizing the scarcity and vulnerability of our natural water resources, the US Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) is taking action through new regulations. PHMSA recently implemented an amendment to pipeline safety regulations that now defines certain coastal waters, the Great Lakes, and coastal beaches as unusually sensitive areas. This impacts over 2,900 additional miles of pipelines that are subject to the integrity management (IM) requirements of inland (49 CFR 195) liquid integrity management regulations.

The new IM coastal regulations

A newly amended definition of "unusually sensitive area" (USA) explicitly states that the Great Lakes, coastal beaches, and certain coastal waters are USAs to determine whether a pipeline is in or could affect a high consequence area (HCA) as defined in § 195.450. Because every USA is also an HCA, the modified definition creates vast new areas classified as HCAs. Under § 195.452, an operator of a hazardous liquid pipeline located in or that could impact an HCA must comply with the new IM requirements.

According to PHMSA's Regulatory Impact Analysis (RIA), the amended USA definition will affect more than 2,900 miles of hazardous liquid and carbon dioxide pipelines, resulting in at least $40 million in compliance costs over a 10-year period, of which $3.1 million will be incurred in the first 12 months.

The IM regulations require pipeline operators located in areas where a spill could affect an HCA to take added steps to mitigate threats to the integrity of those pipelines by operating and maintaining them with an effective Integrity Management program. These measures require operators to devote additional analysis, assessment, and remediation resources to protect high consequence areas from pipeline releases that could adversely affect human health and safety and cause environmental damage.

The entire hazardous liquid rule, which is titled “Transportation of Hazardous Liquids by Pipeline,” is rather complex, but a summary is provided in Figure 1 below:

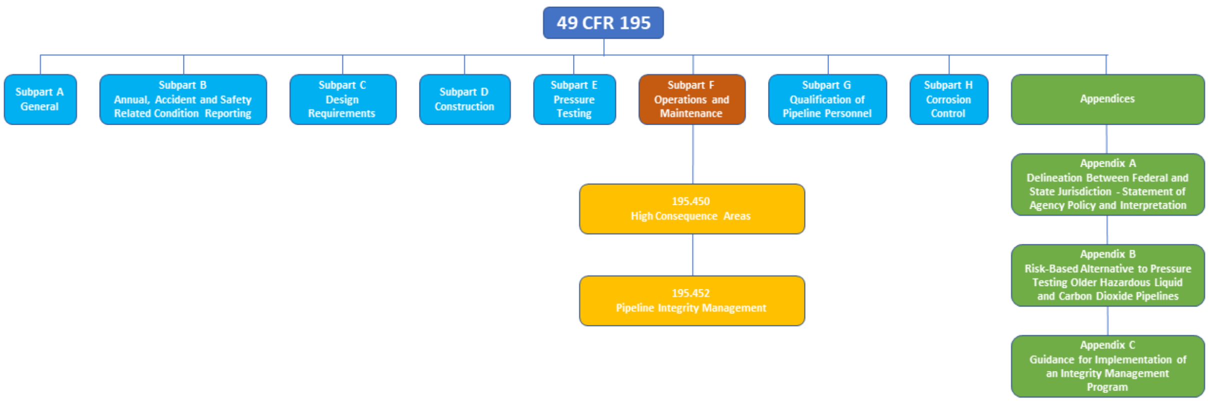

Figure 1: 49 CFR 195 High-Level Outline
click to enlarge

As a further addition to the above rule structure, PHMSA released an additional final rule titled “Pipeline Safety: Safety of Hazardous Liquid Pipelines,” which became effective on July 1, 2020. In this addendum to the 49 CFR 195 regulations, the following was added:

- Extend reporting requirements to specific hazardous liquid gravity and rural gathering lines.
- Require inspections of pipelines in areas affected by extreme weather or natural disaster.
- Require integrity assessments at least once every ten years (using inline inspection tools or other technology) of onshore, ILI inspectable, hazardous liquid pipeline segments located outside of HCAs.
- Extend the required use of leak detection systems beyond high consequence areas, except for offshore gathering and regulated rural gathering pipelines.
- All pipelines in or affecting HCAs must be capable of accommodating inline inspection tools within 20 years.

There have been further regulatory changes, and more changes can only be expected.

How operators can comply

The recent interim final rule was designed to protect from hazardous liquid pipeline accidents similar to the 2010 Marshall, MI, and the 2015 Refugio Beach, CA, oil spills. Furthermore, ensuring that events like an anchor strike that damaged the Line 5 pipeline in the Straits of Mackinac are quickly identified and remediated before they result in environmental damage.

Although the newly regulated 2,900 miles of pipeline seem minor in comparison to the nation's more than [2.6 million miles of pipelines](), they are in some of the most sensitive areas that, if something goes wrong, have a significant impact on a finite resource. Operators with pipelines now blanketed by federal regulations have the challenging task of adjusting current Integrity Management Plans (IMP) or developing and following an entirely new IMP. The IMP must consist of the following elements:

1. A process for identifying pipelines that could affect an HCA, including USAs (see §§ 195.6, 195.450, Appendix C to part 195, "Guidance for Implementation of an Integrity Management Program").
2. An analysis of pipeline safety risks that integrates all available information about pipeline integrity and potential consequences (§ 195.452(g)). Data integrity and accuracy are critical to the success of this stage and sometimes the most complex challenge of all.
3. A plan for scheduling and performing baseline assessments (§ 195.452(c)) - deciding how to inspect the pipelines for the threats a risk assessment has highlighted. The techniques available include In-Line Inspection (ILI), Direct Assessment, Hydrotest, and other emerging technologies.
4. Define the criteria for performing remedial action in response to pipeline integrity issues identified during assessments or other analyses (§ 195.452(h)).
5. A continuous process for scheduling, performing and interpreting integrity assessments and evaluations (§ 195.452(j)).
6. Identifying "preventative and mitigative measures" to protect the pipeline from identified integrity threats (§ 195.452(i)).
7. Developing and following procedures for evaluating the effectiveness of the IM program (§ 195.452(k)).
8. A process to ensure integrity assessment results and information analysis is performed by qualified personnel (§ 195.452(f)(8)).

While it does not change any existing integrity management requirements, the interim final rule extends the scope of the existing current IM requirements to additional mileages of hazardous liquid pipelines. The designated coastal waters and coastal beaches will now receive the same protection as was previously afforded to the Great Lakes.

Technology available for IM segments

Risk tools continue to advance, with an increasing move toward more quantitative methods instead of simple, qualitative, index-based methods. Indeed, the use of semi-quantitative methods yields the accuracy of quantitative methods together with the versatility of qualitative methods when quantitative data doesn't exist. The increased use of quantitative data is expected to lead to a more efficient allocation of maintenance and repair resources and improved integrity. Although the revised regulations are not driving a surge of new technologies, liquid pipeline operators have some of the most advanced and effective ILI technologies to choose from, like Magnetic Flux Leakage tools (MFL) (shown in Figure 2, on next page), Transverse Field MFL, Ultrasonic Wall Measurement, and Ultrasonic Crack Detection.

In-line-Inspection (ILI) tools are built to travel inside a pipeline and collect real-time data as they go, but which tool should be used for which defects? *MFL* technology is used to detect corrosion in a pipeline by measuring volumetric metal loss and accurately identifying imperfections, such as dents. Although the accuracy of MFL

tools comes with a larger sizing tolerance for metal loss (typically ±10 percent wt), it is one of the most popular inspection tools for in-service pressurized pipelines, principally due to its low cost and long track record.

Typically, an MFL tool consists of two or more bodies. One body is the magnetizer with the magnets and sensors, and the other body houses the electronics and batteries. Magnetic sensors are mounted between two magnets and then connected to the pipe wall with brushes. The connection creates a magnetic circuit as the tool travels inside the pipe with the flow of the product. The sensors detect the magnetic flux leakage caused by the metal loss in the pipe wall. Separate caliper sensors measure the magnitude of internal restrictions such as dents.

Ultrasonic Wall Measurement measures the remaining wall thickness of the pipe and can be used in finite element calculations to determine the remaining strength. This technique is more costly but provides a highly accurate survey of corrosion and will also identify and size laminations as well as dents. However, line cleanliness can become an issue for ultrasonic technologies.

Figure 2: MFL Vehicle (Courtesy of Baker Hughes, a GE Company)

Ultrasonic Crack Detection uses sound waves to detect axially orientated cracks and other pipeline defects. Ultrasonic testing of cracks in pipelines is performed using an angled beam. As its name implies, angle beam testing is used to locate cracks and discontinuities that are oriented axially along the pipeline and perpendicular to the surface of the pipe. However, if the crack is sloping or orientated circumferentially, this inspection technology may often either fail to detect it or struggle to size it accurately. In addition, this method takes time, as the data processing and analysis of an ultrasonic ILI tool data is very complex.

Multiple inspection technologies may be required to detect varying types of pipeline defects. Operators must first know what they are looking for and then match the ILI technology to that task.

Conclusion

The regulatory environment for pipeline operators is complex, technically challenging, and ever-changing. However, pipeline operators of all sizes have access to experts within the pipeline integrity management industry, providing the skills and experience to help operators navigate these waters effectively.