

pipelines could reasonably involve a combination of integrity assessment techniques and enhanced leak detection.

- The proposed rule applies to transmission pipelines, as that term is defined in § 192.5. There may be some transmission pipelines operating at less than 20% SMYS that are covered by the proposed rule. Pipelines operating at that low stress level are unlikely to rupture and therefore, pose little risk. We have requested comment on establishing longer reassessment intervals for these low stress lines.

- As a part of its regular surveillance program operators would have to determine whether new construction activity or newly identified recreational activity may add pipe segments to those that can affect an HCA. When such conditions are identified, but no less than annually, the operator must reevaluate which pipeline segments can affect HCAs.

(g) How Is the Baseline Assessment To Be Conducted? Proposed § 192.763(g)

The proposed rule requires that an operator must select the assessment technologies best suited to effectively determine the susceptibility to failure of each pipe segment that could impact an area of potentially high consequences. Assessment tool selection should be based first on the threats to which a segment is susceptible, and second on which assessment techniques can reasonably be applied. More than one method and/or tool may be required to address all the threats to which a pipeline segment is susceptible. The order in which assessment is carried out must take into account priorities determined by a risk assessment. In addition, the proposed rule stipulates that an operator must assess the integrity of the line pipe by applying one or more of the techniques below depending on the threats to which the segment is susceptible:

- Internal inspection tool or tools for detecting corrosion and deformation anomalies as appropriate. For guidance on selecting appropriate internal inspection tools an operator must refer to ASME/ANSI B31.8S standard.
- Pressure test conducted in accordance with subpart J of part 192.
- Direct assessment method for external corrosion threats, internal corrosion threats, stress corrosion cracking, and third party damage (if other assessment methods are not feasible). This method must be carried out in accordance with the ASME/ANSI B31.8S standard and the specified proposed requirements.

- Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify RSPA/OPS 180 days before conducting the assessment.

The proposed rule requires operators to evaluate and assess for third party damage. For gas transmission pipe segments in Class 3 and 4 locations, the major cause of failure is third party damage. This probably results from a higher level of excavation activity in higher populated areas, combined with the fact that thicker and stronger pipe in classes 3 and 4 are less susceptible to corrosion failure. The vast majority of third party damage failures (approximately 90%) occur at the time the third party contact occurs. However, a small fraction of these failures are delayed after the initial contact (e.g., the rupture at Edison, New Jersey). Therefore, some consideration needs to be given to delayed failures. The primary cause of delayed failure from third party damage is believed to be cyclic fatigue from pressure cycling. Gas pipelines are not typically subject to this type of pressure fluctuation.

Given the considerations above, it is clear that lowering the risk associated with third party damage requires that the third party damage threat must be addressed through comprehensive preventive measures. In addition, each operator must evaluate whether cyclic fatigue of sufficient magnitude or other loading condition (including ground movement, suspension bridge condition) necessitate a periodic assessment for dents and gouges. These evaluations must assume the presence of deep dents, and determine whether known and anticipated loading conditions would lead to failure of such hypothesized dents. The results of these evaluations together with the criteria used to evaluate the significance of this threat must be documented in the operators integrity management plan. Operators must assess segments which are vulnerable to delayed failure following third party damage using ILI tools such as deformation or geometry tools. Direct assessment may be used as primary assessment method for third party damage, if no other approach is feasible. Direct assessment has been successfully used to screen piping for the presence of significant residual third party damage, thereby supporting evaluation of the need for additional assessment and focusing on the segments where the use of internal inspection tools is most necessary. Under such conditions, it may be used in combination with data collection and integration to evaluate segment

susceptibility to third party damage. In addition, operators unable or who believe it unnecessary to use a geometry tool must excavate and directly examine indications from ILI runs or from direct assessment that are suspected of resulting from third party damage. The comprehensive preventive measures employed must be documented in the operators integrity management program, and measures of their effectiveness established and monitored.

To address manufacturing and construction defects (including seam defects), the rule proposes that an operator must a pressure test at least once in the life of the segment unless the operator can document in its assessment plan why pressure testing is not required. At anytime the historic operating pressure or other stress conditions is anticipated to change, then the operator must assess the pipeline using appropriate assessment technology prior to making the change in operating condition. The methods an operator selects to assess low frequency electric resistance welded (ERW) pipe or lap welded pipe susceptible to seam failures must be capable of assessing seam integrity and of detecting corrosion anomalies.

The present understanding of the conditions leading to failure from materials and construction defects has improved significantly as a result of analyzing failure experience. For example, while some pre-1970 ERW piping has experienced failures resulting from seams defects, only certain manufacturers' pipe has demonstrated susceptibility to this type of failure. In addition, a once-in-a-life pressure test has proven to significantly lower the likelihood of failure in these susceptible pipe segments. Further, piping that has not been hydro-tested has shown susceptibility only when operating parameters are changed significantly. Therefore, careful analysis of industry operating experience and comparison of the root causes of historic failures with the operators pipe will allow operators to determine the risk of failure from these mechanisms. Incident root cause analysis also indicates that any anticipated increase in operational pressure will require the operator to perform a hydro-test prior to changing operational characteristics. This requirement applies even if an operator plans to increase operating pressure from the historic level, but not to exceed the MAOP.

*Time period.* Each operator must prepare a baseline assessment plan that documents the order in which each pipeline segment will be assessed according to level of risk the segment