Subject Matter Study Report

**Pipeline Fitness-for-Service Assessments:**

**Need for Pipeline Fracture Initiation Control**

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**Pipeline Fitness for Service Assessments:**

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**Executive Summary**

Federal pipeline safety regulations include many generally stated requirements on pipeline integrity issues, but not how to perform these assessments. The American Society of Mechanical Engineers pipeline codes, B31.4 and B31.8 do not contain specific methods on how to perform these pipeline integrity assessment requirements.

Both pipeline safety regulations and pipeline codes strive to keep regulatory and code requirements simple for non-technical pipeline personnel. However, issues on pipeline integrity are complex and require specialized engineering knowhow to perform the activities properly. These pipeline integrity issues should not be overly simplified at the expense of public safety.

Other industries, especially petrochemical plants and refineries, have identified the need for and methods to perform these complex piping integrity assessments. The source for these methods and solutions is American Petroleum Institute (API) 579/American Society of Mechanical Engineers (ASME) FFS-1 on Fitness-for-Service. The fitness-for-service are generally based on pressurized facilities that follow ASME B31.3. A Fitness-for-Service standard is needed for pipelines. Such a task is feasible and would “close the loop” on pipeline integrity compliance. Rigorous inspection and testing requirements will be required. Rigorous stress analyses and fracture mechanics assessments will be required.

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**Pipeline Fitness for Service Assessments:**

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**Introduction**

Various American Petroleum Institute (API) and American Society of Mechanical Engineers (ASME) codes and standards for pressurized equipment and piping systems have provided rules for the design, fabrication, inspection, and testing of new facilities. These codes and standards cover:

1. Determination and analysis of fluids to be handled, operating temperature ranges, and operating pressure ranges;
2. Materials properties required for operating conditions;
3. Sources of allowable materials to be used;
4. Specifications for joining, fabrication, and construction requirements;
5. Inspection and nondestructive testing to ensure compliance with design requirements, drawings, specifications, and imperfection limits;
6. Pressure testing; and
7. Start up and operating procedures.

However, these codes and standards focus on initial design, construction, inspection, and testing, but do not address requirements for pressurized equipment and piping systems to maintain an adequate level of integrity and safety when degraded with time and operating conditions. The rule of “don’t fix it until it’s broke” cannot apply for pressured equipment and piping systems handling and transporting hazardous materials. Minimum standards, procedures, and practices are needed to ensure that pressurized equipment and piping systems maintain a minimum level of integrity during their service life to provide safety and environmental protection. Where time and operating conditions have degraded the strength and integrity of facilities handling and transporting hazardous materials, changes must be made to lower operating conditions to accommodate the losses in integrity or parts of a facility must be repaired or replaced.

Inspections to detect and determine the degradation and other physical conditions of pressurized equipment and piping systems are challenging and expensive. Sometimes facilities have to be removed from service to allow needed inspection and testing of the equipment for degradation and integrity assessment activities. For refineries, chemical plants, gas plants, and power plants, most of the pressurized equipment and piping is aboveground and are somewhat accessible. However, pipelines are usually underground which introduces additional external degradation problems and greatly increases the cost of inspection. Despite the inaccessibility of buried pipelines, pipelines are expected to address integrity problems before they occur. Pipeline companies are expected to have zero tolerance in releases of hazardous materials that may affect people’s lives and the environment.

Fitness-for-service (FFS) concepts and procedures have been developed and used by other industries to ensure that potentially degraded pressurized facilities are unlikely to fail. The process of gathering needed data and performing an FFS analysis is far more complex than normally used to design, operate, and maintain a new pipeline. Unfortunately, pipeline companies often leave these activities to personnel with very limited technical knowledge and inadequate compliance procedures. This is a major flaw in pipeline safety that needs to be corrected.

**Industry Fitness-for-Service Standards**

There are no fracture initiation control standards, guides or recommended practices written specifically for pipelines. However, there are general industry standards and hundreds of reports prepared on the subject that have application to pipelines. One such document that treats the subject of fracture initiation control that is applicable to pipelines is American Petroleum Institute (API) 579/American Society of Mechanical Engineers (ASME) FFS-1 on Fitness-for-Service. The introduction section to this document contains the following information:

1. The ASME and API new construction codes and standards for pressurized equipment provide rules for the design, fabrication, inspection, and testing of new pressure vessels, piping systems, and storage tanks.
2. These codes and standards do not provide rules to evaluate equipment that degrades while in-service and deficiencies due to degradation or from original fabrication that may be found during subsequent inspections.
3. Fitness-for-service (FFS) assessments are quantitative engineering evaluations that are performed to demonstrate the structural integrity of an in-service component that may contain a flaw or damage.
4. This standard provides guidance on conducting FFS assessments using methodologies specifically prepared for pressurized equipment.
5. The guidelines in this standard can be used to make decisions to repair, derate, replace, or take no action to determine that pressurized equipment containing flaws and/or damage identified by inspection can operate safely over a specified period of time.
6. FFS assessments in this standard are recognized and referenced in API Codes and Standards including API 510, API 570, and API 653 as suitable means for evaluating the structural integrity of pressure vessels, piping systems, and storage tanks.
7. The assessments in this Standard may also be applied to pressure containing equipment constructed to other recognized cods and standards.

API Standard 1160, *Managing System Integrity for Hazardous Liquid Pipelines* was first published in November 2001. This pipeline standard references API 579 on fitness-for-service determination and API 570 on piping inspection. The scope of API 1160 contains the following information:

1. The use of this standard is not limited to pipelines regulated under Title 49 CFR Part 195.
2. The principles embodied in integrity management are applicable to all pipeline systems.
3. This standard is specifically designed to provide proven practices to the pipeline operator in pipeline integrity management.

Unfortunately, API 1160 in Section 9.6 includes a “Strategy for Responding to Anomalies Identified by In-Line Inspections” that is not consistent with API 579 or ASME B31.4. API 1160 lists the anomaly conditions in Section 452 of Title 49 CFR Part 195 that require an inspection and response by the pipeline operator of certain in-line inspection anomalies. However, Section 452 of Title 49 CFR Part 195 also indicates that recognized industry standards must be followed unless Section 452 specifies otherwise.

**Federal Pipeline Safety Regulations**

Title 49 CFR Parts 191, 192, and 195 each contain conflicting requirements between normal maintenance requirements and integrity management assessments. Normal maintenance requirements for all pipelines include:

1. Section 191.23 on safety-related conditions of gas pipelines requires assessment and reporting of any of the following uncorrected conditions that exist within 220 yards of any building intended for human occupancy or outdoor place of assembly.
   1. Unintended movement or abnormal loading that impairs the serviceability of a pipeline.
   2. Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength.
   3. Any malfunction or operating error that causes the pressure of a pipeline to rise above its maximum allowable operating pressure (MAOP) plus the overpressure allowance for pressure control and limiting devices.
   4. Any condition that could lead to an imminent hazard and causes a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.
2. Section 195.55 on safety-related conditions of hazardous liquid pipelines requires assessment and reporting of any of the following uncorrected conditions that exist within 220 yards from any building intended for human occupancy or outdoor place of assembly.
   1. General corrosion that has reduced the wall thickness to less than that required for the maximum operating pressure.
   2. Localized corrosion pitting to a degree where leakage might result.
   3. Unintended movement or abnormal loading on a pipeline that impairs its serviceability.
   4. Any material defect or physical damage that impairs the serviceability of a pipeline.
   5. Any malfunction or operating error that causes the pressure of a pipeline to rise above 110 percent of its maximum operating pressure.
   6. A leak in a pipeline that constitutes an emergency.
   7. Any condition that could lead to an imminent hazard and causes a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.
3. Section 192.143 on design of pipeline components requires each component of a pipeline:
   1. Must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service.
   2. If design based on unit stresses is impractical for a particular component, design may be based on a pressure rating established by the manufacturer by pressure testing each component or a prototype of the component.
4. Section 192.144 on qualification of metallic components not manufactured in accordance with a referenced document in Part 192, the component is qualified for use in a pipeline if:
   1. Visual inspection of a cleaned component shows that no defect exists which might impair the strength or tightness of the component and
   2. The document under which the component was manufactured as equal or more stringent requirements of a document currently or previously listed in 192.7 or Appendix B in the following areas:
      1. Pressure testing,
      2. Materials, and
      3. Pressure and temperature ratings.
5. Section 192.159 requires each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.
6. Section 192.161 requires:
   1. Each pipeline and its associated equipment must have enough anchors or supports to:
      1. Prevent undue strain on connected equipment,
      2. Resist longitudinal forces caused by a bend or offset in the pipe, and
      3. Prevent or dampen out excessive vibration.
   2. Each exposed pipeline must have enough supports or anchors to protect the exposed pipe from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipeline and its contents.
   3. Free expansion or contraction between supports or anchors may not be restricted and provision must be made for service conditions.
   4. Each underground pipeline connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.
7. Section 192.317 on protection from hazards requires:
   1. The operator must take all practical steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the line to move or sustain abnormal loads.
   2. Offshore pipelines must be protected from damage by mud slides, water currents, hurricanes, ship anchors, fishing anchors, and vessels.
   3. Each aboveground transmission line or main, not located offshore or in inland navigable waterways must be protected from accidental damage by vehicular traffic or other similar causes by being placed in a safe distance from the traffic or by installing barricades.
8. Section 192.319 on installation of pipe requires when installed in a ditch, each transmission line to be operated at a hoop stress of 20 percent or more of SMYS must be installed so that:
   1. Pipe fits the ditch so as to minimize the stresses and protect the pipe coating.
   2. A firm support is provided under the pipe.
9. Section 192.327 requires when an underground structure prevents the minimum specified amount of cover, the transmission line or main is to be provided with additional protection to withstand anticipated external loads.
10. Section 195.106(d) requires:
    1. The minimum wall thickness of the pipe may not be less than 87.5 percent of the wall thickness required for the internal design pressure of the pipe.
    2. Anticipate external loads and external pressure that are concurrent with internal pressure must be considered.
    3. After determining the wall thickness for the internal design pressure, the nominal wall thickness must be increased as necessary to compensate for these concurrent loads.
11. Section 195.110 on external loads requires:
    1. Anticipated external loads must be provided for in designing the pipeline.
    2. The expansion and flexibility requirements in Section 419 of ASME B31.4 must be followed.
    3. Pipe and other components must be supported in such a way that the support does not cause excessive localized stresses.
    4. In designing attachments to pipe, the added stress to the wall of the pipe must be computed and compensated for.
12. Section 192.485 corrosion remedial measures requires:
    1. Each segment of transmission line with general corrosion and a remaining wall thickness less than required for the MAOP must be replaced, repoured, or the MAOP reduced commensurate with the strength of the pipe based on actual remaining wall thickness.
    2. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion.
    3. Each segment of transmission pipe with localized corrosion pitting to a degree where leakage might result must be replaced, repaired, or the MAOP reduced commensurate with the strength of the pipe based on actual remaining wall thickness.
    4. The strength of corroded pipe based on actual remaining wall thickness may be determined by the procedures in ASME B31G or AGA PR #3-850 (RSTENG).
13. Section 192.555(b) on uprating the MAOP to a pressure that will produce a hoop stress of 30% or more of the SMYS requires:
    1. Design, testing, operating, and maintenance history shall be reviewed to determine if the proposed increase is safe and consistent with Part 192 and
    2. Make repairs, replacements, or alterations in the segment of pipeline necessary for safe operation at the increased pressure.
14. Section 192.55(c) allows an operator to increase the MAOP up to the limits allowed in Section 192.619 using as test pressure the highest test or operating pressure ever experienced in the pipeline segment.
15. If Section 192.555(c) does not permit a high enough MAOP, Section 192.555(d) allows an operator to:
    1. Conduct a new pressure test to the requirements of a new line in the same location or
    2. For a line in a Class 1 location that has not been pressure tested, the MAOP can be increased to 80% of the design pressure allowed for a new line of the same material.
16. Section 192.605(c) on abnormal operations requires:
    1. Operator response to investigate and correct the causes of any foreseeable malfunction of a component or personnel error which may result in a hazard to persons or property.
    2. After abnormal operations have ended, check sufficient critical locations in the system to determine continued safe operation and integrity of the pipeline system.
17. Section 192.611 on change in class location requires if the hoop stress corresponding to the established MAOP is not commensurate with the new class location and the pipeline segment is in satisfactory physical condition, the MAOP must be confirmed or lowered. Part 192 generally allows one class location change without affecting the established MAOP.
18. Section 192.613 on continuing surveillance requires:
    1. An operator shall monitor changes in the following operating and maintenance information and data to determine when changes occur and appropriate action needs to be taken to address the changes:
       1. Class location,
       2. Failures,
       3. Leakage,
       4. Corrosion,
       5. Cathodic protection requirements, and
       6. Other appropriate operating and maintenance conditions.
    2. Determine which pipeline segments are in satisfactory condition and which segments are in unsatisfactory condition.
    3. Determine whether a pipeline segment in unsatisfactory condition creates an immediate hazard.
    4. Initiate a program to reduce the MAOP, recondition, or phase out each unsatisfactory condition segment that does not create an immediate hazard.
    5. If an immediate hazard exists due to an unsatisfactory condition segment, the segment is to be shut down until the unsatisfactory conditions are eliminated.
19. Section 192.617 on investigation of failures requires:
    1. Analysis of each accident and failure to determine the causes and
    2. Take action needed to minimize the possibility of a recurrence of each failure.
20. Section 192.619 on determination of MAOP requires the operator to determine the maximum safe operating pressure after considering the history of the segment, particularly known corrosion and actual operating pressures.
21. Section 192.7703 requires:
    1. No person may operate a segment of pipeline unless it is maintained in accordance with Subpart M.
    2. Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.
22. Section 195.401 on general operating and maintenance requirements includes:
    1. Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time.
    2. If the adverse safety condition presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.
    3. When an operator discovers a condition on a pipeline in a high consequence area, the operator must correct the conditions as required in Section 195.452(h).
    4. No operator can operate the following pipelines unless they were designed and constructed in accordance with Title 49 CFR Part 195:
       1. An interstate pipeline, other than a low-stress pipeline, on which construction was begun after March 31, 1970.
       2. An intrastate pipeline, other than a low-stress pipeline, on which construction was begun after October 20, 1985.
       3. A low-stress pipeline on which construction was begun after August 10, 1994.
23. Section 195.402(c)(4) requires operators must determine which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned.
24. Section 195.402(c)(5) and (6) require:
    1. Operators shall analyze accidents to determine their causes and
    2. Operators shall minimize the potential for hazards identified under 195.402(c)(4) and the possibility of recurrence of accidents.
25. Section 195.402(d) on abnormal operations requires:
    1. An operator must have and follow procedures to address events when design limits have been exceeded.
    2. An operator must respond to, investigate, and correct the cause(s) of:
       1. Any malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property.
       2. Check the pipeline after abnormal operation has ended at sufficient critical locations to determine if safe operation and pipeline integrity can be assured.
26. Section 195.424 on movement of in-service pipe requires an operator may move any line pipe unless the pressure in the line section involved is reduced to not more than 50 percent of the allowable maximum operating pressure.
27. Section 195.452(b)(1) requires the operator to develop a written integrity management program that addresses the risk in each segment of pipeline.
28. Section 195.452(b)(4) requires the operator to follow “recognized industry practices” in carrying out the integrity management program unless an alternative practice is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection.
29. Section 195.452(f) requires the integrity management program must include:
    1. An analysis that integrates all available information about the entire pipeline and consequences of a failure.
    2. Criteria for remedial actions to address integrity issues raised by the assessment methods and the information analysis.
    3. A continual process of assessment and evaluation to maintain a pipeline’s integrity.
    4. A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information analysis.
30. Section 195.452(h) requires:
    1. An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment or information analysis.
    2. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce the pipeline’s integrity.
    3. An operator must be able to demonstrate that the remediation of the condition(s) will ensure the condition(s) is unlikely to pose a threat to the long-term integrity of the pipeline.
    4. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline.
31. Section 195.452(j) requires:
    1. After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area.
    2. An operator must establish five-year intervals, not exceeding 68 months, for continually assessing the line pipe’s integrity.
    3. An operator must establish the intervals based on the factors specified in Section 195.452(e), the analysis of the results of the last integrity assessment, and the information analysis required by 195.452(g).
    4. An operator may be able to justify a longer assessment interval on a segment of line pipe based on a reliable engineering evaluation.
32. Section 192.911 on elements of an integrity management plan requires:
    1. An identification of threats to each pipeline segment in a high consequence area (HCA).
    2. Data on each threat must be integrated and a risk assessment conducted on each threat and each covered segment.
    3. Covered segments must be prioritized according to risk assessment results.
    4. Provisions for remediating conditions found during an integrity assessment.
    5. A plan for continual evaluation and assessment.
    6. Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.
    7. Compliance with ASME B31.8S.
33. Section 192.913(a) requires an operator to choose between using a performance-based integrity management program or a prescriptive-based program. Either type of integrity management program shall comply with ASME B31.8S.
34. Sections 192.913(b) and (c) require an operator to meet the following requirements if it chooses to deviate from a prescriptive-based program.
    1. Meets or exceeds all requirements in ASME B31.8S.
    2. Develop and implement a comprehensive risk assessment process.
    3. Program includes and has fully integrated all available risk factor data.
    4. A procedure for applying lessons learned from assessment of covered pipeline segments.
    5. A procedure for evaluating every incident, including its cause(s) within the operator’s sector of the pipeline industry for its implications and applications to the operator’s entire pipeline system and to the operator’s integrity management program for covered pipelines in HCAs.
    6. A performance measurement process that demonstrates the operator’s program has been effective in ensuring the integrity of covered segments by controlling the identified threats to the covered segments.
    7. A performance analysis that supports:
       1. The operator’s desired integrity reassessment interval and
       2. The operator’s remediation methods to be used on covered segments.
    8. An operator must have completed at least two integrity assessments on each covered pipeline segment.
    9. An operator must be able to demonstrate that each assessment effectively addressed the identified threats on the covered segments.
    10. An operator must remediate all anomalies identified in the more frequent assessment according to Section 192.933 and incorporate the results and lessons learned into the operator’s data integration and risk assessments.
    11. Once an operator has demonstrated that it has satisfied the requirements in Section 192.913(b), the operator may deviate from the prescriptive requirements of ASME B31.8S in the following instances:
        1. Time frame for reassessments as provided in Section 192.939 except for some methods such as confirmatory direct assessment which must be carried out at intervals no longer than seven years.
        2. The time frames for remediation in Section 192.933 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment.
35. Section 192.917(a) requires the following activities to identify all potential threats to each covered pipeline segment.
    1. Potential threats listed in ASME B31.8S,
    2. Time dependent threats,
    3. Static or resident threats,
    4. Time independent threats, and
    5. Human error.
36. Section 192.917(b) requires the operator to gather and integrate all relevant data on the entire pipeline system that could be relevant to a covered segment.
37. Section 192.917(b) also requires an operator must conduct a risk assessment that follows ASME B31.8S, Section 5:
    1. The risk assessment shall consider identified threats for each covered segment.
    2. The risk assessment shall be used to prioritize the covered segments for the baseline assessments, reassessments, and determination of additional preventative and mitigative measures are needed for each covered segment.
38. Section 192.917(e)(1) on actions to address third party damage include:
    1. Determine from data integration the susceptibility of each covered segment to third party damage.
    2. If susceptible to third party damage, the operator must implement additional preventative measures under Section 192.935 and monitor the effectiveness of these measures.
    3. If an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate the data from these assessments with encroachments or foreign line crossings to define where potential third party damage may exist in the covered segment.
39. Section 192.917(e)(2) on actions to address “cyclic fatigue” include:
    1. Operator must evaluate whether cyclic fatigue or other loading condition (including ground movement) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment.
    2. An evaluation must assume the presence of threats in the covered segment(s) that could be exacerbated by cyclic fatigue.
    3. An operator must use the results from the evaluation together with criteria used to evaluate the significance of a threat to the covered segment to prioritize the integrity assessments.
40. Section 192.917(e)(3) on actions to address manufacturing and construction defects include:
    1. If an operator identifies manufacturing and/or manufacturing defects in a covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects.
    2. Consider results of prior assessments on the covered segment.
    3. Manufacturing and construction defects are allowed to be considered to be stable if the operating pressure on a covered segment has not increased over the maximum operating pressure experienced during the previous five (5) years.
    4. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for conducting integrity assessments.
       1. Operating pressure increases above the maximum operating pressure experienced during the preceding five (5) years,
       2. MAOP increases, and/or
       3. Stresses leading to cyclic fatigue increase.
41. Section 192.917(e)(4) on low frequency electric resistance welded pipe, lap welded pipe, or other pipe specified in ASME B31.8S in any covered or non-covered pipeline segment requires the operator to use an assessment technology or technologies with a proven application capable of assessing pipe seam integrity and seam corrosion anomalies if:
    1. A seam failure has been experienced or
    2. Operating pressure has increased over the maximum operating pressure experienced during the previous five (5) years.
42. Section 192.917(e)(5) requires if corrosion could affect the integrity on a covered segment, the operator must evaluate and remediate all pipeline segments (both covered and non-covered) with similar coating and environmental characteristics.
43. Section 192.921 requires the integrity of the pipe in each covered segment be assessed by one or more of the following methods:
    1. Internal inspection tool,
    2. Pressure test,
    3. Direct assessment on corrosion related threats,
    4. Other technology the operator demonstrates can provide an equivalent level of understanding, and/or
    5. Method or methods best suited to address the identified threats.
44. Section 192.933 on actions to be taken to address integrity issues requires:
    1. An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment.
    2. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline’s integrity.
    3. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.
45. Section 192.935 on additional preventative and mitigative measures requires:
    1. An operator must take additional measures beyond those already required in Part 192 to prevent a failure and to mitigate the consequences of a pipeline failure in a HCA.
    2. An operator must base the additional measures on the threats the operator has identified to each pipeline segment.
46. Section 192.937 on a continual process of evaluation and assessment to maintain a pipeline integrity requires:
    1. After completing the baseline integrity assessment, an operator must continue to assess the line pipe of that segment at the intervals specified in Section 192.939 and periodically evaluate the integrity of each covered pipeline segment.
    2. An operator must reassess the integrity of a covered segment no later than seven (7) years after the baseline assessment unless the integrity evaluation indicates an earlier assessment is needed.
    3. The period of reassessments must be based on data integration and risk assessment of the entire pipeline as specified in 192.917.
47. Section 192.939 on required reassessment intervals requires:
    1. The maximum reassessment intervals depend on the hoop stress, assessment methods, the identified threats, and the analysis of the results of the prior integrity assessment.
    2. For pipelines operating at a hoop stress above 30% of the SMYS:
       1. The maximum reassessment interval by single allowable assessment method is seven (7) years.
       2. A longer than seven (7) year reassessment period is allowed, within the seven (7) year period, the operator conducts a confirmatory direct assessment on the covered segment in addition to the earlier risk assessment.
       3. Comply with ASME on reassessment intervals if stated conditions are met.

**Conclusions**

The requirements in the U.S. DOT pipeline safety regulations are fragmented, piece-meal, inconsistent, and inadequate to prescribe details on conducting pipeline integrity fitness-for-service assessments. Therefore, one has to back off and consider the apparent intent of the U.S. DOT pipeline safety regulations and the various pipeline safety acts passed by the U.S. Congress since 1968. The following information has to be considered in determining the intent of the pipeline safety regulations.

1. The regulations contain minimum safety standards.
2. Regulatory requirements standards are vaguely stated as general performance-based standards and depend on the regulated industry to develop detailed compliance procedures. However, the U.S. DOT has never established performance requirements in regulations.
3. The pipeline industry for various reasons has not maintained a technical staff of subject matter experts capable of performing complex engineering analysis.
4. The U.S. DOT has not considered the level of technical competence needed to solve complex engineering problems.
5. The U.S. DOT does not have a technical staff of subject matter experts capable of complex engineering analysis in pipeline regulations.
6. Because of the lack of subject matter expertise in pipeline integrity analysis, the pipeline industry and U.S. DOT have tried to use overly simplified analysis and “guesswork” for complex engineering analysis.
7. The growth in pipeline integrity knowledge gas been stymied since the early 1980s; however, knowledge on integrity matters in other industries have continued to grow.
8. If pipeline safety is to advance from its present static and inadequate status, more emphasis must be given to development of subject matter, engineering experts using proven methods developed by other industries.
9. Unique pipeline problems cannot only be solved with simple solutions by the pipeline industry. The problems on pipeline safety and integrity have been experienced by other industries operating pressurized equipment and piping who are ahead of the pipeline industry.

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