Subject Matter Study Report

**Petroleum Pipeline Industry Use of Inadequate Integrity**

**Acceptance Limits in Operations and Maintenance**

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By

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**Executive Summary**

The stated limits of acceptability of imperfections, mechanical damage, and corrosion in pipelines indicates when a pipeline company must take corrective action to remove or repair the condition. These are one of the most important requirements in pipeline regulations and industry codes.

The stated limits on imperfections, mechanical damage, and corrosion must be precisely stated to ensure consistent compliance. Unfortunately, this is not the case in Title 49 CFR Parts 191, 192, and 195. The authority on setting limits of acceptability of imperfections, mechanical damage, and corrosion are delegated to each individual pipeline company. Pipeline companies are also delegated the authority on corrective actions to be taken.

Solutions to these adverse regulatory safety conditions are feasible and available in areas outside normal use by pipelines. Solutions to these problems include:

1. Comprehensive proactive inspection and fitness-for-service regulations.
2. Pipeline integrity is a complex process and overly simplified regulation will never be successful.
3. Pipeline industry codes such as American Society of Mechanical Engineers (ASME) B31.4 and B31.8 will never be able to fully address the fitness-for-service (FFS) needs for all pipelines, because of their consensus approval process.
4. A comprehensive FFS standard for both gas and hazardous liquid pipelines is needed similar to American Petroleum Institute (API) 579/ASME FFS-1.

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**Introduction**

Prior to 1979, ASME B31.4 in Section 451.6 contained the following limits of acceptability of imperfections, mechanical damage, and corrosion in pipelines:

1. Injurious gouges, grooves, and dents shall be removed from the pipe as a cylinder or repaired with a full encirclement sleeve.
2. All welds found during maintenance inspection to have injurious defects shall be repaired.
3. Generally corroded pipe with a remaining wall thickness less than the pipe manufacturing specification shall be repaired, replaced, or the pipe’s operating pressure may be reduced based on the actual remaining wall thickness.
4. Pipe with localized corrosion pitting to a degree where leakage might result, shall be repaired, replaced, or the pipe’s operating pressure may be reduced based on the actual remaining wall thickness.

In 1979, ASME B31.4 Section 451.6 was revised as follows for piping operated at a hoop stress of more than 20% SMYS:

1. Gouges and grooves having a depth greater than 12.5% of the nominal wall thickness shall be removed or repaired.
2. Dents which affect the curvature of the pipe at a pipe seam or girth weld shall be removed or repaired.
3. Dents containing a scratch, gouge, or groove shall be removed or repaired.
4. Dents exceeding a depth of ¼ inch in pipe NPS 12 and smaller, or 2% of NPS in diameters larger than NPS 12 shall be removed or repaired.
5. All arc burns shall be removed or repaired.
6. All cracks shall be removed or repaired.
7. All welds found to have imperfections not meeting the standards of acceptability in API 1104 shall be removed or repaired.
8. If general corrosion has reduced the wall thickness to less than the wall thickness required for the design pressure of the pipe decreased by an amount equal to the manufacturing tolerance, the pipe shall be removed, repaired, or the operating pressure reduced in accordance with Section 451.7.
9. Pipe with localized corrosion pitting shall be repaired, replaced, or operating at a lower operating pressure based on the fracture mechanics models developed in the AGA Pipeline Research Program.
10. Areas where grinding has removed the remaining wall thickness to less than the pipe manufacturing tolerance decreased by the pipe wall manufacturing tolerance, may be analyzed the same as localized corrosion pitting.
11. All pipe containing leaks shall be removed or repaired.

In 1979, Section 451.7 was added to ASME B31.4 covering derating a pipeline to a lower operating pressure based on the same fracture mechanics models in Section 451.6 for corrosion and areas where grinding was used for repairs.

In 2006, Section 451.6 was renamed “Pipeline Integrity Assessments and Repairs”. Previously, Section 451.6 applied to direct examination of potentially adverse integrity conditions to measure actual dimension of imperfections and mechanically damaged areas. ASME B31.4 did not address errors in estimates of recorded anomalies during in-line inspection.

**Title 49 CFR Part 195 Requirements**

Subpart F on operations and maintenance contains the following requirements in Section 195.401.

1. No operator may operate or maintain its pipeline system at a level of safety lower than required by this subpart (F) and the procedures it is required to establish under Section 195.402(a).
2. When an operator discovers a condition on a pipeline within the scope of the mandatory integrity management program rules in Section 195.452, the operator must correct the condition as prescribed in Section 195.452(h).
3. When 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. However, if the 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 conditions.

The above requirements in Title 49 CFR Part 195 for compliance purposes can be summarized as follows:

1. Every pipeline subject to Title 49 CFR Part 195 may contain conditions that create “an immediate hazard to persons or property”.
2. An operator must establish minimum levels of safety to operate each pipeline.
3. If these established levels of safety are not met, the affected pipelines are not allowed to operate unless actions are taken to meet these levels.
4. These minimum levels of safety must be covered operating and maintenance procedures developed by the operator for each pipeline.
5. These operating and maintenance procedures must address records on each pipeline necessary to establish and maintain the essential levels of safety required for operation of each pipeline.
6. The levels of safety to be achieved before a pipeline can be operated must cover all aspects of pipeline materials, design, construction, testing, inspection, corrosion control, operations, maintenance, and emergency response.
7. Because Title 49 CFR Part 195 does no specifically prescribe the procedures required to establish and maintain these minimum levels of safety, each operator must establish specific compliance minimum levels of safety.

For years, the pipeline industry has used the physical and location differences between pipelines as an argument against regulatory efforts to specifically address the Pipeline Safety Acts and related safety issues. The U.S. DOT for some unexplained reason has taken a passive role on prescribing and enforcing pipeline safety regulations. This passive role was at its peak during the 1990s. Today, the U.S. DOT is caught in a “Catch 22” condition based on its past practices as it occasionally strives to move forward on pipeline safety issues.

**Current ASME B31.4 Pipeline Integrity Management Requirements**

Pipeline integrity management requirements in the 2016 edition of ASME B31.4 include:

1. Each operator of pipelines designed in accordance with this Code should consider the need for periodic integrity assessments of those pipelines.
2. An integrity assessment may consist of:
	1. A hydrostatic test,
	2. An in-line inspection (ILI) followed by remediation of anomalies indicated by the inspection to be possibly injurious, or
	3. Other technical means that can provide a level of integrity assessment equivalent to a hydrostatic test or an ILI.
3. For guidance on the integrity assessment process, the operator may refer to API 1160.
4. Each operator should develop criteria for evaluating anomalies identified through ILI methods using visual inspection or through other technical means. API 1160 provides guidance for evaluating anomalies.
5. Defect repair criteria and repair methods are described when addressing anomalies discovered on their pipelines. A pipeline operator may elect to perform an engineering critical assessment (ECA) to identify alternate criteria or other mitigative methods as defined in API 1160.
6. Limits of imperfections and anomalies are given in Section 451.6.2 and include:
	1. Areas of internal or external corrosion metal loss with a maximum depth greater than 80% of the actual wall thickness shall be removed or repaired.
	2. An appropriate fitness for purpose (FFS?) criterion may be used to evaluate the longitudinal profile of corrosion caused metal loss in:
		1. Base metal of the pipe or
		2. Non-preferential corrosion caused metal loss that crosses a girth weld or impinges on a submerged arc welded seam.
	3. Areas of external corrosion with a maximum depth of 20% of the depth required for the hoop stress based design pressure need not be repaired.
	4. Measures should be taken to prevent further external corrosion.
	5. An area of corrosion with a maximum depth greater than 20%, but less than or equal to 80% of the wall thickness shall be permitted to remain in the pipeline without repair as long as the pressure does not exceed a “safe” level.
	6. Generally acceptable methods for calculating a “safe” operating pressure include ASME “Modified B31G” an effective area (e.g. RSTENG).
	7. For pipelines subject to unusual axial loads, lateral movement and settlement, or pipelines comprised with yield-to-tensile ratios exceeding 0.93, an ECA shall be performed.
	8. When dealing with internal corrosion, consideration should be given to the uncertainty related to the indirect measurement of wall thickness and the possibility that internal corrosion may require continuing mitigative efforts to prevent additional metal loss.
	9. Two or more areas of corrosion-caused metal loss separated by areas of full wall thickness may interact in a manner that reduces the remaining strength to a greater extent than the individual areas. Interacting limits are based on:
		1. Six times the wall thickness in the circumferential direction and
		2. One inch in the longitudinal direction.
	10. Pipe containing leaks shall be removed or repaired.
	11. Any grooving, selective or preferential corrosion of the longitudinal seam of electric weld pipe shall be removed or repaired.
	12. Gouges and grooves shall be evaluated by nondestructive testing and removal by grinding. Where grinding removes the wall thickness by more than 12.5%, the ground area shall be removed or evaluated for acceptability as external corrosion.
	13. Dents exposed for examination with any of the following characteristics shall be removed or repaired unless an engineering evaluation can demonstrate that other mitigative action as defined in API 1160 will reduce the risk to an acceptable level.
		1. Dents containing gouges, scratches, cracking, or other stress riser.
		2. Dents containing metal loss from corrosion or grinding where less than 87.5% of the nominal wall thickness remains.
		3. Dents that affect pipe curvature at a girth weld or longitudinal pipe seam.
		4. Dents deeper than 6% of NPS or 0.250 inch for NPS 4 and smaller.
	14. The absence of cracks in dents shall be confirmed by magnetic particle or dye penetrant methods.
	15. Arc burns shall be removed or repaired by grinding.
	16. Verified cracks except shallow crater cracks or star cracks in girth welds shall be considered defects and removed or repaired unless engineering evaluations shows they pose no risk to pipeline integrity.
	17. An anomaly created during the manufacture of the steel or the pipe that exists in a pipeline that has been subject to a hydrostatic test to a minimum of 1.25 times its maximum operating pressure shall not be considered a defect unless the operator has reason to suspect the anomaly has been enlarged by pressure-cycle-induced fatigue. If it is established that the anomaly has been or is likely to become enlarged by pressure-cycle-induced fatigue, the anomaly shall be removed or repaired.
	18. Areas having a hardness level corresponding to Rockwell C35 or more shall be removed or repaired.
	19. Blisters shall be considered defects and shall be removed or repaired.
	20. For small buckles or wrinkles which exhibit no cracks, no repair is required if the difference between high and low points is less than 2% of the nominal pipe diameter if the hoop stress is equal to or less than 20,000 psi.

**API RP 1160, “Managing System Integrity for Hazardous Liquid Pipelines”**

Requirements pertaining to analysis of anomalies detected by ILI surveys include:

1. Different ILI tools are designed to address anomalies created by different threats. No one ILI tool is capable of addressing all threats to pipeline integrity.
2. Pipeline operators are to perform integrity assessments to cover all the threats and risks in each pipeline segment to receive an integrity assessment.
3. Table 1 covers the capabilities of various ILI tools to detect and to size various threats in a pipeline. Listed threats include:
	1. External and/or internal metal loss,
	2. Selective seam corrosion,
	3. Axially oriented stress corrosion cracking (SCC),
	4. Axially oriented cracks,
	5. Axially oriented crack like manufacturing defects such as hoop cracks and cold welds,
	6. Circumferential cracking,
	7. Dents,
	8. Wrinkles and buckles,
	9. Expanded pipe,
	10. Laminations,
	11. Hard spots,
	12. Evidence of strain, and
	13. Bends and curvature.

(Leaks are omitted from the list.)

1. Other threats listed in ASME B31.4 not listed in Table 1 include:
	1. Leaks;
	2. Arc burns;
	3. Gouges, grooves, notches, and scratches;
	4. Gouges, grooves, notches, scratches, and/or corrosion cracking incidents.
2. Magnetic flux leakage (MFL) are the most commonly used ILI tools, but none can detect cracking. The only anomalies that can be sized with MFL ILI tools are internal and external corrosion.
3. None of the ILI tools can detect and measure gouges, grooves, notches, scratches, and corrosion in dents.
4. Detectability will be less than 100% for certain anomalies below the threshold size and the pipeline operator should understand the limitations of each tool prior to its use.
5. The pipeline operator should determine the amount of tool error with each ILI tool run by excavating and examining a representative number of anomalies.
6. The statistical distribution of errors should be considered in the evaluation of anomalies for remedial action.
7. The routine grading of anomalies by an ILI vendor may not be adequate to assess the integrity of certain anomalies.
8. To effectively respond to anomalies, operators should know the operating parameters of the pipeline including:
	1. Allowable maximum operating pressures,
	2. Potential pressure during a transient or abnormal event, and
	3. Maximum potential steady state operating pressure.

(Sources of pipeline stress other than hoop stress from internal pressure are not addressed in API 1160, but API 1160 references API 579/ASME FFS-1 for compliance purposes.)

1. Pipeline operators may obtain guidance on the evaluation of the effects of cracks from API 579-1/ASME FFS-1 or BSI 7910.
2. Pipeline operators should arrange to receive the final ILI report for an inspected segment within a timely period after completion of the ILI tool run. For anomalies that fall into the category of an “immediate concern”, operators should take action within five (5) days involving:
	1. Further data integration/evaluation,
	2. Additional assessments,
	3. Excavation, and
	4. Repair.
3. Pressure redirection should be considered until each anomaly of “immediate concern” can be addressed.

**Conclusions**

1. A comprehensive proactive inspection and fitness-for-service regulations are needed to comply with pipeline regulations.
2. Because of the burial of 99+% of pipelines and the wide range of pipeline ages, materials, locations, operating conditions, and past operating and maintenance practices, a “one-size-fits-all” approach to pipeline safety will never be appropriate.
3. Pipeline integrity and safety management is a complex process and overly simplified regulation will never be successful.
4. Pipeline industry Codes such as ASME B31.4 and B31.8 will never be able to fully address the fitness-for-service needs of all pipelines, because of their consensus approval process.
5. ASME B31.4 and B31.8 have long ago outgrown their usefulness, because of the consensus process and dependency on pipeline operators for content.
6. Extensive FFS procedures and evaluations are needed to cover the full range of adverse integrity conditions in pipelines.
7. FFS procedures for pipelines must address the lack of integrity management records in most pipelines through conservative assumptions and through more extensive testing and inspection than addressed in regulations and in industry Codes, Standards, and recommended practices.
8. Although the range operating conditions for some pipelines may be narrow, the range of integrity conditions can be great and often unknown until a significant or even catastrophic release occurs and a comprehensive failure investigation is conducted.
9. Data used in FFS calculations and computational procedures need to be based on conservative values not averages. The ranges of uncertainty need to be known.
10. Statistical methods used by ILI vendors for determining performance of ILI surveys and by pipeline operators to verify ILI performance are not based on proper engineering and scientific methods.
11. Statistical analyses of data used in FFS analyses should be determined using engineering/scientific-based statistical analyses such as that in ASTM documents.
12. FFS methods in industry documents are based on the requirements for a single adverse integrity condition. When a facility has numerous adverse integrity conditions, a higher confidence level is needed for each condition to ensure reliability of the entire pipeline facility.
13. Extreme value analyses and probability of exceedance statistical methods have been used on pipelines and should be performed on all pipeline integrity assessments.
14. Neither ASME B31.4 nor API 1160 cover the issues addressed in items 1 through 8 above.
15. Neither ASME B31.4 nor API 1160 address the FFS requirements for the full range of risks and threats found in buried pipelines.
16. API 1160 only addresses hoop stress from internal pressure. Pipelines have numerous sources of loads and stresses that need to be addressed in FFS analysis.
17. No combination of ILI tools can detect and size all the defects and damage required in ASME B31.4.
18. Only pressure testing can address all the threats requiring remedial action in ASME B31.4.
19. The interacting distance for areas of corrosion are not consistent with API 579/ASME FFS-1. The criteria for interacting areas of localized corrosion and other imperfections should be.
20. A comprehensive FFS standard for both gas and liquid pipelines is needed similar to API 579/ASME FFS-1.

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