Subject Matter Study Report

**Fitness for Service Analyses in Pipeline Integrity Management**

November 2016

(Revised June 20, 2017, January 2018, and January 2019)

By

Royce Don Deaver, P.E.

DEATECH Consulting Company

203 Sarasota Circle South

Montgomery, Texas 77356

Restricted Use of This Report

Any person using any part of this report without the assistance and involvement of the author and DEATECH Consulting Company shall assume any and all risk and responsibility on the application of the information contained in the subject report.

Neither DEATECH Consulting Company nor the author of this report assume any liability with respect to the use of, or for any and all damages resulting from the use of any information disclosed in this report.

**Fitness for Service Analyses in Pipeline Integrity Management**

**Executive Summary**

Federal pipeline safety regulations include many, but not all, of the activities required to perform pipeline integrity management. Neither Title 49 CFR Part 192 nor Title 49 CFR Part 195 include a definition of integrity management other than a listing of activities to be performed to keep the transported fluids inside the pipeline and out of the environment. Once hazardous fluids are released into the ground, water, or air, the effectiveness of steps to control these hazards to public health and safety and to the environment are very limited. The adverse effects of hazardous fluids releases are not reversible.

Extensive and comprehensive activities are needed to keep the fluids inside the pipeline facilities. However, the stated requirements in Federal and State regulations are generally stated as performance requirements and do not state how to perform compliance activities. Because of the lack of detail in Federal pipeline safety regulations, enforcement activities are limited and usually ineffective.

The American Society of Mechanical Engineers (ASME) Pipeline Codes, B31.4 and B31.8, do not contain specific details on how to perform the numerous pipeline integrity management activities. The ASME Codes indicate that pipelines vary too much in age, size, locations, environmental conditions, and operating and maintenance practices to prepare a Code for all conditions.

An available source of detailed specification level integrity management is found in American Petroleum Institute (API) Standard 579-1/ASME FFS-1 on Fitness for Service. If the principles of this document are rigorously applied to pipeline integrity management, the vast majority of integrity management issues will be solved.

R. D. Deaver, P.E.

DEATECH Consulting Company

rddeaver.com

**Fitness for Service Analyses in Pipeline Integrity Management**

**Pre-operations Design Integrity Management Activities**

Pipeline integrity management involves extensive activities and records in each of the following steps to ensure that design requirements are met:

1. Determination of transportation capacity and functional requirements.
2. Determination of locations and routing of facilities.
3. Determination of applicable requirements regulations, codes, standards, recommended practices, and company specifications, procedures, and design criteria.
4. Determination of geo-technical and external loading conditions at various locations of various parts of the pipeline.
5. Determine current and future population and development activities along the pipeline locations.
6. Detail design of each piping component and items of pipeline equipment.
7. Determine corrosiveness of the external environment of the pipeline and the corrosive properties of fluids to be transported and stored to determine allowable pipeline materials and corrosion prevention requirements and related facilities.
8. Perform potential consequences analyses of potential spills and releases of fluid for various parts of the pipeline.
9. Determine design requirements to accommodate integrity tests and inspections to be performed for integrity assessments of various parts of the pipeline system.
10. Establish records for continual integrity management activities of the pipeline system.

Pipeline integrity management involves extensive activities and records in each of the following steps to ensure material procurement requirements are met.

1. Ensure design requirements of each piping component and item of equipment are fully described and recorded.
2. Ensure material and equipment procurement specifications are adequate for each of the piping components and items of equipment and recorded.
3. Ensure each vendor and supplier of equipment are capable of meeting the requirements of each type of pipe, piping component, and item of equipment.
4. Monitor manufacturing of equipment and piping and inspection upon delivery to ensure all materials and equipment meet or exceeded stated requirements.

Pipeline integrity management involves extensive activities and records during fabrication and construction to ensure piping components and pipeline equipment meet comprehensive construction and installation requirements including:

1. Ensure construction specifications are comprehensive and appropriate for pipeline facilities to be installed.
2. Ensure competent contractors are used for installation of the pipeline system.
3. Ensure an adequate number of competent and independent inspectors are used to monitor activities of each contractor.
4. Ensure each part of the pipeline system is inspected and tested when practical to ensure compliance with stated design requirements.
5. Pressure test all parts of the pipeline intended to contain the fluids to be transported.
6. Establish and maintain records and comprehensive procedures for continual integrity management activities of the entire pipeline system.

The term “fitness for service” is comparable to the term “serviceability” in pipeline regulations. Other comparable terms defined in ASME B31.8 include:

1. **Engineering assessment** means a documented assessment using engineering principles of the effect of relevant variables upon service or integrity of a pipeline system and conducted by or under the supervision of a competent person with demonstrated understanding of and experience in the application of engineering and risk management principles related to the issue being addressed.
2. **Engineering critical assessment** means an analytical procedure based upon fracture mechanics that allows determination of the maximum tolerable sizes for imperfections and conducted by or under the supervision of a competent person with demonstrated understanding of and experience in the application of the engineering principles to the issue being assessed.
3. **Integrity** means the capability of the pipeline to withstand all anticipated loads plus the margin of safety established by this Code.
4. **Integrity assessment** means a process that includes inspection of pipeline facilities, evaluating the indications resulting from the inspections, examining the pipe using a variety of techniques, evaluating the results of the examinations, characterizing the evaluation by defect type and severity, and determining the resulting integrity of the pipeline through analysis.
5. **Inspection** means the use of nondestructive testing technique or method.

The above term “integrity assessment” as written only applies to evaluation of data from in-line inspection surveys. The term “engineering assessment” is more proper for the “fitness for service” analyses that need to be performed. The term “fitness for service” is not defined in pipeline regulations and Codes.

Some of the minimum design related fitness for service (FFS) requirements in 49 CFR Parts 192 and 195 include:

1. Materials for pipe and piping components must be:
   1. Able to maintain the structural integrity of the pipeline under anticipated temperature and environmental conditions (192.53).
   2. Able to withstand the internal pressures and external loads anticipated for the pipeline system (192.103 and 195.112).
   3. Chemically compatible with fluids they transport (192.53).
   4. Qualified for use (192.53).
2. Design activities must address:
   1. Anticipated external loads, earthquakes, vibration, thermal expansion, and contraction (195.110).
   2. Expansion and flexibility of piping in accordance with ASME B31.4 (195.110).
   3. Support piping in such a way not to cause excessive localized stresses (195.110).
   4. Protection against over pressure (192.195, 192.199, and 192.201).
3. Construction activities must address:
   1. Qualification of welding specifications and procedures (192.255 and 195.214).
   2. Welds must be inspected to meet the standards of acceptability in API 1104 (192.241, 192.243, and 195.228).

Federal regulations generally require fitness for service analysis of pipeline systems, but neither the Federal regulations nor pipeline industry standards and recommended practices cover explicit details on how to perform fitness for service analyses.

Fitness for service analyses are needed to ensure proper compliance of many of the above design and construction requirements.

**Pipeline Operations and Maintenance Integrity Management**

Pipeline operations and maintenance integrity management (OMIM) should begin before and initial operation of the pipeline to ensure any design, materials, and construction requirements were not overlooked especially for future fitness for service anaylses. Complete and integrated records are needed at the beginning of pipeline operations. The pipeline system should begin with a “clean bill of health” as far as design, materials, and construction compliance activities are concerned. Complete records should be developed and maintained for operations and maintenance integrity management activities.

Design and construction requirements are generally intended for a pipeline lasting for 50 or more years if the pipeline only experiences minor deterioration from its original installation conditions. When piping or equipment deterioration occurs or design conditions beyond the original limits occur, a fitness for service analyses should be performed to determine if:

1. Operating limits need to be changed or
2. Repair replacements are needed now or in the future in adversely affected parts of the pipeline.

The integrity assessment and fitness for service analyses must ensure that the minimum factors of safety are maintained throughout the operating life of each pipeline facility.

**Goals of Fitness for Service Analyses**

Operating and maintenance integrity management generally involves a three part process to:

1. Inspect the pipeline whenever possible to detect potentially adverse integrity conditions,
2. Conduct a fitness for service analysis to determine the effects of each potentially adverse condition on the integrity of the pipeline, and
3. Maintain the minimum factor of safety of each pipeline facility.

The fitness for service or FFS for each adverse integrity condition should determine one or more of the following actions.

1. Immediate derating or reduction in allowable maximum operating pressure.
2. Repair and replacement of piping or equipment.
3. Time period to perform a follow up reassessment of the FFS of the potential adverse integrity conditions.
4. Increased inspection and testing requirements to monitor the potentially adverse integrity condition and detection of similar conditions in other parts of the pipeline system.

**Integrity Management Requirements in Federal Rules**

Minimum operating and maintenance integrity rules in 49 CFR Parts 191 and 192 include:

1. Safety related piping conditions not repaired or replaced within 10 days of discovery within 220 yards of a building intended for human occupancy or outdoor place of assembly or within the ROW of an active railroad or must be reported to the U.S. Department of Transportation (U.S. DOT). (Section 191.24) These conditions include:
   1. General corrosion in a pipeline operating at a hoop stress of 20% or more of the specified minimum yield strength (SMYS) where the remaining wall thickness is less than the thickness needed for the maximum allowable operating pressure in the pipeline.
   2. Localized corrosion pitting to a degree where leakage might occur.
   3. Unintended movement or abnormal loading that impairs the serviceability of a pipeline.
   4. Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20% or more of SMYS.
   5. A leak that constitutes an emergency.
   6. Any condition that could lead to an imminent hazard and causes a 20% or more reduction in operating pressure or shutdown of operation of a pipeline.
2. For transmission lines, any abnormal condition when operating design limits have been exceeded requires the operator to [192.605(c)]:
   1. Respond to, investigate, and correct the cause(s) and
   2. Check variations from normal operating design limits at sufficient critical locations in the pipeline system to determine continued integrity and safe operations.
3. For a change in class location, required studies include (192.609 and 192.611):
   1. Comparison of original design, construction, and testing procedures with present requirements for the new class location;
   2. Determine operating and maintenance history of the segment;
   3. Determine physical condition of the segment and the extent it can be determined from available records; and
   4. MAOP of the segment to be the “maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure” (see 192.619).
4. Continuing surveillance shall be performed on each pipeline facility to determine operating and maintenance related changes and take appropriate action concerning those changes (192.613):
   1. Each segment will be analyzed to determine if it is in satisfactory condition or in unsatisfactory condition.
   2. Each segment found in unsatisfactory condition shall be analyzed to determine if any “immediate hazard” exists.
   3. Any segment in unsatisfactory condition shall be reconditioned, phased out, or have its MAOP reduced (see 192.619) if no immediate hazard exists.
   4. Any segment in unsatisfactory condition where an immediate hazard is determined to exist, shall be shut down from operation.
5. Each pipeline’s damage prevention program shall include inspection activities during and after excavation activities are done near the pipeline to verify the integrity of the pipeline [192.614(c)(6)].
6. A continuing public awareness program shall include activities to “assess the unique attributes and characteristics of each pipeline and pipeline facility” [192.616(b)].
7. Each pipeline accident and failure shall be analyzed to determine the causes of the failure and actions to be taken to minimize the possibility of a recurrence (see 192.617).
8. The MAOP of each pipeline segment and pipeline facility shall be determined to be the lowest of the following (see 192.619):
   1. Design pressure(s);
   2. Hydrostatic test divided by the appropriate test factor;
   3. Pressure determined to be the maximum safe pressure after considering the history of the segment (or pipeline facility), particularly known corrosion and actual operating pressures; or
   4. Highest actual operating pressure for five (5) years prior to the grandfather determination date (July 1, 1970 for transmission lines).
9. An overpressure allowance of 10% over the MAOP provided for operation of pressure limiting and relief facilities (see 192.195 and 192.201)
10. Each pipeline segment “that becomes unsafe” must be replaced, repaired, or removed from service [see 192.703(b)].
11. Hazardous leaks must be repaired promptly [see 192.703(c)].
12. A pipeline patrol program shall observe surface conditions on and adjacent to the transmission line rights-of-way for factors affecting safety and operations (see 192.705).
13. Immediate temporary measures shall be taken to protect the public whenever a leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40% of the SMYS [see 192.711(a)].
14. An operator must make permanent repairs on its pipeline system as soon as feasible [see 192.711(b)].
15. Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40% of SMYS must be (see 192.713):
    1. Removed and replaced, or
    2. Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe, and
    3. Operating pressure must be at a safe level during repair operations.
16. Each weld that is found to be unacceptable under Section 192.241(c) (API 1104) shall be (see 192.715):
    1. Removed and replaced or
    2. Repaired.
17. Each segment of transmission line with general corrosion and a remaining wall thickness less than that for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on the actual remaining wall thickness. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is to be considered as general corrosion [192.485(a)].
18. Each segment of transmission line with localized corrosion pitting to a degree where leakage might result must be [see 192.485(b)]:
    1. Replaced or repaired or
    2. The operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.
19. The strength of the pipe based on actual remaining wall thickness may be determined by the procedures in ASME B31G or AGA PR 3-805 (RSTRENG) subject to the limitations in these procedures.
20. The integrity management program shall include (192.909):
    1. Identify all threats to the entire pipeline system,
    2. Identify all threats to each pipeline segment (and pipeline facility) in a high consequence area,
    3. Baseline integrity and serviceability assessment plan,
    4. Provisions and procedures for analyzing and remediating conditions (safety related) found during each integrity assessment,
    5. Process for continual evaluation and integrity assessment,
    6. Provisions for adding preventative and mitigative measures to protect the high consequence area(s) in each covered pipeline segment (and facility),
    7. A quality assurance plan,
    8. Comprehensive data collection and integration process, and
    9. Integrity reassessment period.
21. Actions that must be taken to address integrity issues are to include [see 192.933(a)]:
    1. Prompt actions to address and evaluate all anomalous conditions the operator discovers during the integrity assessments.
    2. Identify all anomalous conditions that could reduce a pipeline’s integrity.
    3. Each remediation action shall ensure each adverse integrity condition is unlikely to pose a threat until the next remediation of the covered segment.
22. An operator must determine any temporary reduction in operating pressure using ASME B31G or AGA PR 3-805 (RSTRENG) or reduce the pressure to a level not to exceed 80% of the pressure when the anomalous condition was discovered [see 192.933(a)(1)].
23. The following conditions discovered during an integrity assessment must be repaired immediately [see 192.933(d)]:
    1. A calculation of remaining strength of the pipe shows a failure pressure less than or equal to 1.1 times the MAOP. Methods of analysis of the discovered conditions include:
       1. ASME B31G,
       2. AGA PR-805 (RSTRENG), or
       3. An alternative equivalent method of remaining strength calculation.
    2. Dent that has an indication of metal loss, cracking, or a stress riser.
    3. An anomaly judged to require immediate action.
24. The following integrity conditions do not require remediation, but must be monitored during subsequent risk assessments and integrity assessments for any change that may require remediation [see 192.933(d)(3)]:
    1. Dent deeper than 6% on the top part of the pipe with a strain less than critical as determined by an engineering analysis.
    2. Dent deeper than 2% that affects pipe curvature at a girth weld or seam weld with a strain less than critical as determined by an engineering analysis considering the weld properties.
25. An operator must conduct a periodic (continual) evaluation as frequently as needed to assure the integrity of each covered segment.
26. An operator must evaluate whether cyclic fatigue or other loading conditions could lead to failure [see 192.917(e)(2)]:
    1. A deformation, including a dent or gouge, and
    2. Other defect.
27. An operator must analyze each covered segment to determine the risk of failure of manufacturing and construction defects [see 192.917(e)(3)].
28. If a covered segment contains low frequency ERW pipe, lap welded pipe, or any other pipe that satisfies the conditions in ASME B31.8S and any segment in the pipeline system has experienced a seam failure during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies.
29. If an operator identifies corrosion on a covered segment that could adversely affect the integrity of the line, the operator must evaluate and remediate all pipeline segments with similar material, coating, and environmental requirements.

Compliance with the above requirements requires a proactive comprehensive inspection, testing, and fitness for service analysis programs. However, the Federal regulators are waiting for the pipeline industry to develop standards to comply with the above requirements. Unfortunately, most pipeline companies no longer have the engineering staff to develop and implement a standard similar to API 579. API 579 is used extensively within other industries with piping systems. There are engineering companies that have the capability to produce such a document for pipeline fitness for service and assist pipeline companies in developing and implementing fitness for service. The required effort will be significant, but the rewards of improved safety should be even greater.

**Need for Comprehensive Pipeline FFS Analyses**

An appropriate FFS method of analyses is required to satisfy each of the above elements in Subpart O in 49 CFR Part 192. However, ASME B31G and AGA RSTRENG are the only partial FFS sources included in 49 CFR Part 192 for gas transmission lines and petroleum trunklines. These two FFS sources have significant application limits that are not addressed in 49 CFR Parts 191, 192, and 195. Both of these sources should be limited to single, isolated spots of volumetric corrosion in the body of pipe. These sources do not apply to mechanical damage, cracks, and crack like defects such as gouges.

Both ASME B31G and AGA RSTRENG were originally designed for integrity evaluation of small isolated corrosion spots on the pipeline based on visual inspection of the exposed pipeline and actual wall thickness measurements. These methods of evaluation were designed or intended to apply to pipelines where hoop stress from internal pressure is the only source of stress.

There is no published pipeline industry Code or recommended practice to cover the wide range of FFS analyses required for the vast number of adverse integrity conditions encountered in pipelines of which 99+% are buried and difficult to inspect because of burial. These adverse integrity and safety conditions beyond hoop stress from internal pressure in perfect geometry pipe include, but are not limited to:

1. General corrosion,
2. Isolated pitting,
3. Interacting corrosion pitting,
4. Selective weld seam corrosion,
5. Circumferential corrosion in girth welds,
6. Circumferential corrosion in the heat affected zone of girth weld,
7. Longitudinal corrosion in the heat affected zone of DSAW pipe,
8. Stress corrosion cracking,
9. Hydrogen stress cracking,
10. Hydrogen induced cracking,
11. Cracking in hard spots,
12. Cracks in gouges and grooves,
13. Cracks in gouges and grooves in dents,
14. Cracking of imperfections in girth welds,
15. Cracking of imperfections in seam welds,
16. Flat spots in pipe,
17. Girth weld misalignment,
18. Pipe seam misalignment,
19. Residual stress in welds,
20. Residual stress in pipe body,
21. Stress from external loadings,
22. Thermal individual longitudinal stress,
23. Construction induced longitudinal stress,
24. Local bending stress due to differences in wall thickness,
25. Delaminations,
26. Fatigue cracking,
27. Corrosion fatigue cracking,
28. Arc burns,
29. Leaks,
30. Ruptures, and
31. Guillotine ruptures.

Title 49 CFR Part 192 in Section 192.907(b) requires compliance with ASME B31.8S and its appendices in developing and carrying out its integrity management program, but only for high consequence areas (HCAs). ASME B31.8S does not fully address FFS issues. ASME B31.8 only partially addresses limited FFS issues in gas pipelines.

Title 49 CFR Part 195 in Section 195.452(b)(6) requires operators to “Follow recognized industry practices in carrying out this section” on integrity management of HCAs. API 1160, “Managing System Integrity for Hazardous Pipelines” has always included API 579 on Fitness for Service as a compliance document. Therefore, for hazardous liquid pipelines, compliance with API 1160, API 579, and other industry standards and recommended practices are required for compliance purposes unless “the operator can demonstrate an alternate practice is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection”.

ASME B31.4 does not fully address FFS issues. ASME B31.4 only partially addresses some FFS issues in hazardous liquid pipelines.

**American Petroleum Institute (API) FFS Standard**

The only extensive oil and gas industry FFS standard is API 579-1/ASME FFS-1 2007 titled *Fitness for Service*. The Foreword section of API 579 contains the following relevant statements.

1. In contrast to the straight forward and conservative calculations that are typically found in design codes, more sophisticated assessment of metallurgical conditions and analysis of local stresses and strains can more precisely indicate whether operating equipment is fit for its intended service or whether particular fabrication defects or in-service deterioration threaten its integrity.
2. Such analyses offer a sound basis for decisions to continue to run as is, or to alter, repair, monitor, retire, or replace the equipment.
3. The standardized fitness-for-service assessment procedures presented in API 579 provide technically sound consensus approaches that ensure the safety of plant personnel and the public while aging equipment continues to operate, and can be used to optimize maintenance and other operation practices, maintain reliability, and enhance the long-term economic performance of plant equipment.

API 579 covers the following FFS issues:

1. Responsibilities of owner-user, inspector, and engineer;
2. Qualification of each party;
3. Application and limits of FFS assessment procedures;
4. Data requirements;
5. Assessment techniques and acceptance data;
6. Remaining life assessment;
7. Remediation;
8. In-service monitoring;
9. Documentation;
10. Brittle fracture assessment;
11. General metal loss assessment;
12. Local metal loss assessment;
13. Pitting corrosion assessment;
14. Hydrogen damage assessment;
15. Weld misalignment assessment;
16. Shell distortion assessment;
17. Crack-like flaw assessment;
18. Creep-range assessment;
19. Fire damage assessment;
20. Dents, gouges, and dent with gouge assessment; and
21. Lamination assessment.

API 579 also includes extensive equations, data, and procedures for detail analysis of potential safety conditions in piping, vessels, and tanks covering:

1. Maximum allowable working pressure (MAWP);
2. Minimum thickness;
3. Stress equations;
4. Internal pressure analysis;
5. External pressure analysis;
6. Weight, wind, and earthquake loads analyses;
7. Stress analysis;
8. Fatigue analysis;
9. Stress intensification analysis;
10. Crack-like flaw analysis;
11. Residual stress analysis;
12. Fatigue analysis;
13. Material properties for a FFS assessment; and
14. In-service deterioration and damage.

Three levels of assessment are covered in API 579 and include:

1. Level 1 assessment procedures are intended to provide conservative screening criteria that can be utilized with a minimum amount of inspection or component information. Level 1 assessments can be performed by plant inspection or plant engineering personnel.
2. Level 2 assessment procedures are intended to provide a more detailed evaluation that produces results that are more precise than those of a Level 1 assessment. In a Level 2 assessment, inspection information similar to that required for a Level 1 assessment are needed; however, more detailed calculations are used in the evaluation. Level 2 assessments would typically be performed by plant engineers or engineering specialists experienced and knowledgeable in performing FFS assessments.
3. Level 3 assessment procedures are intended to provide the most detailed evaluation which produces results that are more precise than a Level 2 assessment. In a Level 3 assessment, the most detailed inspection and component information is typically required. The recommended analysis is based on numerical techniques such as the finite element method or experimental techniques when appropriate. A Level 3 assessment is primarily intended to use by engineering specialists experienced and knowledgeable in performing FFS assessments.

FFS acceptance criteria include:

1. Allowable stress limits,
2. Remaining strength factors, and
3. Failure assessment diagrams.

FFS assessment procedures in API 579 generally assume that all relevant information is known. However, in most instances many of the important pipeline variables and information are not known to a high degree of accuracy. In such cases, statistical analyses and sufficiently conservative estimates of the independent variables must be made to ensure an acceptable safety margin. The following types of analyses can be used to provide insight into the dependency of the FFS results with variations in the input parameters to assure an acceptable safety margin, especially when assumptions and estimates are made. These procedures include:

1. Sensitivity analysis,
2. Probabilistic analysis, and/or
3. Partial safety factors.

The purpose of a sensitivity analysis is to determine if a change in any of the input variables has a strong influence on the safety factors. The sensitivity should consider the effects of different assumptions and available data with regard to:

1. Loading conditions;
2. Material properties; and
3. Flaw types, sizes, and shapes.

The sensitivity analysis should be able to demonstrate that when realistic variations are made in the input parameters, the assessment results do not dramatically change and demonstrate an adequate safety margin is maintained. If a strong dependency is found on any input parameter, the degree of accuracy should be improved with additional testing and/or inspection in establishing that parameter.

A probabilistic analysis can be used to evaluate the dependency of the safety margin on the uncertainty of input variables. Reliability methods or other analytical techniques, such as Monte Carlo simulation, are used to estimate the probability of failure.

Partial safety factors can be applied to each variable or parameter in the assessment procedures. The partial safety factors are probabilistically calibrated to reflect the effect that each of the variables or parameters has on the probability of failure. In API 579, partial safety factors are to be utilized in the assessment of crack-like flaws.

Once the FFS is conducted and the piping component is determined to be acceptable at the current time, a remaining life should be determined for the piping component. The remaining life analysis is used to:

1. Establish an appropriate inspection and reassessment interval,
2. An in-service monitoring plan, and
3. Determine the need for remediation.

When the future damage rate or progression cannot be estimated easily or accurately or the remaining life is short, in-service monitoring should be used. In-service monitoring allows future damage or conditions leading to future damage can be assessed, or confidence in the remaining life estimates can be increased. Monitoring methods include:

1. Corrosion probes (or coupons) to determine corrosion rate,
2. Hydrogen probes to asses hydrogen activity,
3. Ultrasonic examination including guided wave methods,
4. Acoustic emission testing to measure metal loss or cracking activity, and
5. Measurement of key process variables and contaminants.

Each FFS assessment part in API 579 provides guidance in calculating a remaining life or time intervals for FFS assessments. The remaining life or maximum reassessment intervals are established on the basis of time to reach the MAWP or a reduced MAWP condition. Remaining life analyses in each assessment part will fall into one of the following three categories:

1. Remaining life can be calculated with reasonable certainty,
2. Remaining life cannot be established with reasonable certainty, or
3. There is little or no remaining life.

API 579 requires a FFS assessment for each joint of pipe and component in a piping system. Like components can be grouped if adequate records are available to support the common grouping characteristics. This is contrary to pipeline practices where assumptions are made that certain lower stress systems can be exempt from integrity or FFS analysis. Even when pipelines are not exempt from analysis, only the line pipe is evaluated for integrity purposes and numerous piping components are not addressed by pipeline operators. API 579 does not allow any pressurized piping component to be overlooked.

**Bibliography**

American Gas Association Final Report on Project PR-3-805, “A Modified Criteria for

Evaluating the Remaining Strength of Corroded Pipe”, 1989.

American Petroleum Institute 579/American Society of Mechanical Engineers FFS-1,

“Fitness for Service”, 2013.

American Petroleum Institute 1160, “Managing System Integrity for Hazardous Liquid

Pipelines”, Second Edition, 2013.

American Society of Mechanical Engineers B31.4, “Pipeline Transportation for Liquids

and Slurries”, 2012.

American Society of Mechanical Engineers B31.8, “Gas Transmission and Distribution

Piping Systems”, 2016.

American Society of Mechanical Engineers B31G, “Manual for Remaining Strength of

Corroded Pipe”, 2012.

Title 49, CFR Part 191, *Transportation of Natural Gas and Other Gas by Pipeline:*

*Annual Reports, Incident Reports, and Safety Related Reports*, 2016.

Title 49, CFR Part 192, *Transportation of Natural Gas and Other Gases by Pipeline:*

*Minimum Federal Safety Standards*, 2016.

Title 49, CFR Part 195, *Transportation of Hazardous Liquids by Pipeline*, 2016.

R. D. Deaver, P.E.

DEATECH Consulting Company

rddeaver.com

January 31, 2019