



June 12, 2012

Docket Management Facility
U.S. Department of Transportation (DOT)
West Building, Room W12-140
1200 New Jersey Avenue, S.E.
Washington, DC 20590

VIA ELECTRONIC FILING (<http://www.regulations.gov>)

Re: Docket No. PHMSA-2012-0024

Pipeline Safety: Information Collection Activities, Revision to Gas Transmission and Gathering Pipeline Systems Annual Report, Gas Transmission and Gathering Pipeline Systems Incident Report, and Hazardous Liquid Pipeline Systems Annual Report

Dear Sir or Madam:

The Interstate Natural Gas Association of America (INGAA) submits this letter per the notice and request for comments (Notice) issued in the referenced docket by the Pipeline and Hazardous Materials Safety Administration (PHMSA) on April 12, 2012, and published in the *Federal Register* on April 13, 2012.¹ INGAA is a non-profit trade association that represents the interstate natural gas transmission pipeline industry. INGAA's members represent approximately two-thirds of the pipelines and over 65 percent of the mileage comprising the U.S. natural gas transmission pipeline system. INGAA members complete PHMSA's gas transmission and gathering annual and incident reports, and their interest in the matters addressed in the Notice is self-evident.

Introduction

Through its proposed amendments to the Gas Transmission and Gathering Pipeline Systems Annual Report (Annual Report), PHMSA plans to collect the data for regulations that could go to the heart of the interstate pipeline industry. The data will be used to support rulemakings (and assess operator progress) in three important areas:

1. Identifying and reporting mileage where records are insufficient to confirm maximum allowable operating pressure (MAOP)

Section 23 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act)² directs pipeline owners and operators to conduct a comprehensive study of the records supporting the MAOP of facilities in class 3 and 4 locations and class 1 and 2 high consequence areas (HCAs).³ PHMSA's proposed revisions, with the additions proposed by

¹ 77 Fed. Reg. 22387.

² Pub.L.No. 112-90 (2012).

³ 2011 Pipeline Safety Act § 23 (adding 49 U.S.C. § 60139(a)).

INGAA, will show how operators have established MAOPs. In those instances where operators have been unable to find traceable, verifiable and complete records, the annual report will provide both a basis to comply with section 23⁴ and a yardstick for measuring operators' progress in establishing MAOPs over time.

2. Reporting progress of testing previously untested mileage for material strength

As stated in the Notice, PHMSA intends to use data provided in the Annual Report to develop regulations "for the testing of previously untested gas transmission pipelines located in [HCAs] and operating at pressure greater than 30 percent of specified minimum yield strength."⁵ The Annual Report, with the changes proposed by PHMSA and the additions proposed by INGAA, will show the progression of mileage where testing for material strength has been completed.

The amended Annual Report will also address a recommendation made by the National Transportation Safety Board (NTSB) made following our industry's incident in San Bruno, California.⁶ Specifically, NTSB recommendation P-11-14 calls for testing of previously untested pipelines.

In addition, the Annual Report will provide data to support PHMSA's efforts in responding to section 5 of the 2011 Pipeline Safety Act, which requires that "the Secretary of Transportation shall evaluate whether integrity management system requirements, or elements thereof, should be expanded beyond high consequence areas..."⁷

3. Reporting mileage that can accommodate in-line (ILI) inspection

The amended Annual Report is intended to address not only the requirements of the 2011 Pipeline Safety Act but also NTSB recommendation P-11-17. NTSB recommendation P-11-17 calls for PHMSA to "Require that all natural gas transmission pipelines be configured so as to accommodate [ILI] tools, with priority given to older pipelines." As amended, the Annual Report will assess how much pipeline mileage currently accommodates ILI.

Instead of mandating a separate study, PHMSA proposes amending the Annual Report to obtain the data required by section 23(a) to develop the strength testing regulations required by section 23(d). INGAA appreciates PHMSA's approach. A one-time study can provide only a snapshot of the transmission pipeline network. Amending the Annual Report will create a dynamic picture showing how various system characteristics improve over time.

⁴ *Id.* (adding 49 U.S.C. § 60139(b)(1)(requiring owners and operators to "identify and submit to the Secretary documentation [on pipeline segments] for which records ... are insufficient to confirm the MAOP").

⁵ 77 Fed. Reg. at 22388 (referencing 2011 Pipeline Safety Act § 23 (adding 49 U.S.C. § 60139(d))).

⁶ NTSB recommendation P-11-14 (relating to the MAOP "grandfather clause" (49 C.F.R. § 192.619(c)) and the testing of previously untested pre-1970 pipelines; and NTSB recommendation P-11-17 (relating to making pipelines capable of accommodating ILI inspection).

⁷ 2011 Pipeline Safety Act § 5(a)(1).

It is essential the amended Annual Report render an accurate and complete picture. Strength testing can cost billions of dollars, both in the process itself and in the cost pipelines and consumers suffer when testing takes lines out of service. Accurate and complete data will enable the development of effective regulations.

As INGAA detailed in its comments on PHMSA's advance notice of proposed rulemaking on gas pipeline safety (ANPRM),⁸ the appropriate standard for assessing pipeline integrity issues is a fitness for service (FFS) methodology. Consistent with adopting an FFS approach, INGAA has identified several enhancements to the proposed Annual Report amendments. Adopting these enhancements will ensure sufficient information is collected to conduct an FFS examination to determine where material strength testing is warranted.

In addition to the Annual Report enhancements supporting FFS, INGAA has identified other improvements for the Annual Report and the Gas Transmission and Gathering Pipeline Systems Incident Report (Incident Report). These revisions are addressed below. Although INGAA's comments generally are framed as changes to provisions of the reports, INGAA recognizes that many of these changes will trigger corresponding changes in the instructions that accompany them. Our proposed changes to the Annual and Incident Reports should be read to include corresponding changes to the instructions.

INGAA appreciates coming to terms on amendments to the Annual and Incident Reports is not the same as carrying the amendments into the forms and developing the software necessary to enable operators to complete the amended forms electronically. INGAA welcomes the opportunity to work with PHMSA to expedite the development of the software and electronic interfaces necessary to make the revised forms available.

Annual Report: Adopting an FFS Approach for Proposed Parts Q and R

Proposed parts Q and R of the Annual Report should be amended to enable using an FFS approach for pre-regulation pipelines.

Proposed parts Q and R are intended to provide information on the amount and nature of the natural gas transmission pipelines that might be subject to the material strength testing regulations contemplated in section 23(d) of the 2011 Pipeline Safety Act.⁹ Parts Q and R should focus on addressing the requirements in section 23, and the proper approach for addressing section 23's requirements is FFS.

A white paper describing the FFS methodology, particularly as applied to assessing construction and materials issues on pre-regulation pipe, is attached as Appendix 1. Consistent with this methodology, INGAA proposes replacing proposed parts Q and R with a substitute, attached as Appendix 2, that would collect the information necessary to characterize the amount of pipe to be addressed through various FFS methods. The FFS process considers:

⁸ *Safety of Gas Transmission Pipelines* (Docket No. PHMSA-2011-0023), 76 Fed. Reg. 53086.

⁹ 2011 Pipeline Safety Act § 23 (adding 49 U.S.C. § 60139(d)).

- A focus on pre-regulation pipe, since pipe installed after March 12, 1970, will have been pressure tested.
- Information on pressure tests other than the 125% of MAOP
- Whether a pipeline operates at or below 30% SMYS

In addition to characterizing pipe for integrity purposes (including possible material strength testing), the FFS process provides a straightforward, common sense approach to defining which pipes can “accommodate the passage of [ILI] devices” per NTSB recommendation P-11-17. INGAA’s substitute tables expressly define “accommodate ILI” to mean pipes that have been inspected by an ILI device — pipeline flow powered, tethered or self-powered — and pipes that the operator plans to subject to inspection by an ILI device. A majority of transmission pipelines can be reconfigured to accommodate an ILI device; however, some lines cannot be reconfigured to accommodate ILI due to space and right-of-way constraints, and some have flows too low to propel an ILI platform. Important to the FFS process is to identify the amount of pipe that can currently accommodate ILI and the amount of pipe an operator plans to reconfigure to accommodate ILI.

Like PHMSA, INGAA intends its changes to the Annual Report to be in place for years to come, both to promote continuity within the Annual Report database and to show the progress of INGAA members in fulfilling their safety commitments under INGAA’s Integrity Management – Continuous Improvement (IMCI) Action Plan.¹⁰ In one case, the forward-looking nature of INGAA’s substitute could lead to some short-term confusion. Section 23 of the 2011 Pipeline Safety Act specifies that by July 2013 operators must identify and document segments in class 3 and 4 locations and class 1 and 2 HCAs “for which records . . . are insufficient to confirm the established MAOP of the segment.”¹¹ Information on record sufficiency is also requested in INGAA’s substitute part Q. Assuming the substitute is adopted into the Annual Report, owners and operators would be collecting information on the record status of their pipeline segments during calendar 2012 and reporting that information to PHMSA in March 2013, which is when the Annual Reports are due but three months before the statutory deadline. While INGAA members can be expected to be diligent in identifying the records status of their pipeline segments, INGAA’s substitute part Q includes a column titled “records review not complete” to account for statutory compliance work that is ongoing when the Annual Report is filed.

Annual Report Part A: Operator Information

Item 5: “Landfill Gas” should not be added to the list of commodity groups.

As proposed, item A-5 would be modified by adding “landfill gas” to the list of commodity groups reported. The addition of landfill gas is carried into at least one other section of the Annual Report (for example, part C).

¹⁰ The IMCI Action Plan can be accessed at: <http://www.ingaa.org/File.aspx?id=15732>.

¹¹ 2011 Pipeline Safety Act § 23 (adding 49 U.S.C. § 60139(b)(1)).

A review of the 2010 Annual Reports shows that out of 1,000 reports, only 12 had entries for landfill gas. To put that in perspective, there were 10 entries for ethylene gas. These small numbers do not warrant changing the report form as proposed. PHMSA is right not to list ethylene gas, and it should not list landfill gas either.

Further, once landfill gas — or synthetic gas for that matter — enters a transmission system, it becomes merely part of the natural gas stream and is indistinguishable. Such is not the case for hydrogen or propane, for example. They are transported in dedicated pipelines. Also, in the case of interconnects, the recipient of the gas at an interconnect point has no way of distinguishing, or perhaps even knowing, whether it is receiving any landfill gas.

INGAA is also concerned about the clarity of the instructions for A.5. The most reasonable interpretation is that, for example, if an operator has 5,000 miles of transmission pipelines carrying natural gas, and a 50-mile hydrogen pipeline, it would submit a separate report for each of these. If that is the case, INGAA requests that the instructions be so clarified.

Item 7: “OCS portions” should be defined to refer to the affected water body, not the OCS block.

As amended, item A-7 will ask for a listing of “OCS portions”. It is not clear what this term means. Listing of large areas such as the Gulf of Mexico or Atlantic Coast would be acceptable; listing by OCS block would require significant extra work.

Annual Report Part F: Integrity Inspections Conducted and Actions Taken Based on Inspection

Direct Examination should be recognized as a distinct means of inspection.

Annual Report items F-1 through F-4 currently recognize three inspection methods: ILI, pressure testing and direct assessment (DA). All other methods are reported in aggregate in item F-5. PHMSA should modify the Annual Report to recognize a fourth means of inspection: direct examination. Direct examination has been defined as “A direct physical inspection, examination and evaluation of an anomaly by a person, which may include the use of non-destructive examination techniques.” The pipe is not inspected by ILI, DA or pressure test but rather is physically examined over its entirety. Operators’ use of this rigorous and recognized inspection technique should be tracked separately, and not aggregated with the “other” methods currently reported in item F-5.

Item F-6d: INGAA recommends not adding separate categories in the report form for number of conditions eliminated by pipe replacement.

Proposed item F-6d would ask for information on conditions eliminated by pipe replacement. INGAA supports the addition of item F-6(d) and recommends PHMSA differentiate the way short replacements and longer replacements are accounted for. INGAA members have always reported replacements made when directly examining pipe as repairs, *i.e.*, replacements made when examining pipe in a bell hole or the extension of a bell hole based on findings, generally one to several joints of pipe.

This approach is consistent with PHMSA regulations starting at 49 C.F.R. § 192.715. For example, under section 192.717 (“permanent field repair of leaks”) one repair option is to “remove by cutting out a cylindrical piece of pipe.” Reporting these shorter pipe replacements as repairs is consistent with past practices. INGAA recommends accounting for anomalies in short replacements as part of repairs in items F-6(b) and F-6(c).

INGAA recommends that anomalies removed using the proposed items F-6(d) and F-6(f) be accounted for on long replacements, *e.g.*, class changes. INGAA recommends that the form be modified to use the general category of “actionable anomalies eliminated.” “Actionable anomaly” is defined in API 1163 and that term should be incorporated in to the Annual Report. The reason for this different approach on long replacements is not all anomalies will be excavated and examined. As a result the operator will not have verified the actual condition found. This would allow an operator to report those anomalies that are determined as actionable based on ILI. Clarifying the reporting of “actionable anomalies” will ensure that reporting is consistent across all operators, and will avoid the reporting of indications that do not meet a criterion for operator action.

Item F-6e: INGAA recommends not adding separate categories in the report form for number of conditions eliminated by pipe abandonment.

To maintain consistency across the Annual Report database, if the pipe is abandoned as a repair, the operator should report all the actionable anomalies that were eliminated by the abandonment as part of the repair.

For the same reasons discussed in INGAA’s comment on item F-6d, operators should instead report “actionable anomalies eliminated.” This would allow an operator to report those anomalies that are determined as actionable based on ILI.

Annual Report Part G: Miles of Baseline Assessments and Reassessments

With the period for baseline assessments largely drawing to a close, the distinction between baseline assessments and reassessments should be eliminated.

At the end of 2012, all baseline assessments are to be completed with the exception of any new HCAs. The number of new HCAs is expected to be relatively small in future years.

Future assessments will predominantly be reassessments for the first time, second time, and beyond. There does not appear to be a need to distinguish baseline assessments from reassessments beyond the 2012 reporting year.

Annual Report Parts H and I: Miles of Transmission and Gathering Pipe By Nominal Pipe Size (NPS)

To avoid confusion and improve the accuracy of the Annual Report database, the instructions for parts H and I should specify that NPS data should be reported as integers, for example 6.625" should be reported as NPS 6.

PHMSA proposes to add two additional pipe diameters to the part H and I tables, and INGAA has no objection to these additions. An issue arises with the instructions for parts H and I, which state that for pipe sizes not listed the operator should report the associated mileage in the "other pipe sizes not listed" cell.

The 2010 Annual Reports show many pipes with an outside diameter (OD) that is not an even number integer, e.g., 6.625" and 31". Rather than continue to add even integer sizes to the part H and I tables, PHMSA should review the current data in order to determine the more common NPSs and adjust the tables to reflect those numbers. Thus, NPS 6.625 should be entered in the tables under "6," and OD 31" pipes should be entered under "other."

Annual Report Part M: Incidents, Failures, Leaks, and Repairs

Item M-1: The columns for "Incidents in HCA Segments" and "Failures in HCA Segments" are redundant and should be removed.

The columns for "Incidents in HCA Segments" and "Failures in HCA Segments" should be removed because they collect the same information owners and operators already provide on the Incident Reports. For example, the Incident Report Form has a category of Equipment Failure, a type of failure. INGAA recommends following an important principle of data base management, which is maintaining one version of data. In this instance that means not duplicating reporting of items already accounted for in the Incident Report.

Annual Report Definitions

For certain key terms, the Annual Report or the instructions for completing it should adopt definitions used generally by the natural gas pipeline industry.

Some of INGAA's comments on the Annual Report rest on commonly accepted industry definitions of key terms. These definitions, detailed below, should be incorporated into the Annual Report or in the instructions accompanying it:

- *Actionable Anomaly.* Anomalies that may exceed acceptable limits, based on the operators' anomaly and pipeline data analysis. (From API 1163, Figure 1.)
- *Direct Examination.* A direct physical inspection of an anomaly by a person, which may include the use of non-destructive examination techniques. An example of direct examination would be an inspection and measurement made on a pipe surface at an excavation.

- *OCS Portion.* The body of water in which the offshore pipeline facilities are located, such as the Gulf of Mexico.
- *Repair.* A pipe repair can include the installation of pressure containing sleeves or non-pressure containing sleeves, replacing a weld or welding to fill in an anomaly, grinding to remove stress concentrators, or pipe replacement. Repair does not include touching-up, re-establishing or replacing coating. Each actionable anomaly repaired shall be counted when a repair method is used that repairs multiple anomalies in one repair. (See examples below)
 - A segment of pipeline is assessed by ILI and a 1000 ft. section is reported to have 150 actionable anomalies, either immediate, scheduled or monitored repair anomalies spread throughout the 1000 ft. section. The operator decides to replace the 1000 ft. of pipe. There were 150 repairs made.
 - A 1000 ft. section of pipeline is assessed by the Direct Assessment methods¹² and the indirect above ground methods show 150 indications warranting examination. Sufficient digs are made and all 150 indications were loss of coating with minimal or no wall loss. The operator re-establishes good coating at all 150 indications. The number of repairs made in this example is zero.
 - A 1000 ft. section of pipeline is inspected by Direct Assessment methods as above and the above ground methods find 150 indications that warrant examination. Sufficient digs are made and all 150 indications have sufficient wall loss that either an immediate, scheduled or monitored condition is found. The operator decides to replace the 1000 ft. of pipe. Number of repairs made is 150.

Incident Report Part C: Additional Facility Information

The proposed additional information for girth welds, items C-3a through C-3h, should be required for all pipe and joint welds.

PHMSA proposes requiring operators to provide more information on incidents involving girth welds. Specifically, operators will need to fill out all the pipe information presently specified in items C-3a through C-3h.

INGAA not only supports this new requirement, it should apply to all three pipe joint weld types shown on the “Weld” line under item 3-h: girth, other butt, and fillet. While the data show that girth welds are the predominant weld failure type, the additional data may be valuable for all weld types.

¹²

E.g., external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA) and stress corrosion cracking direct assessment (SCCDA).

Incident Report Part G5: Material Failure of Pipe or Weld

Consistent with experience to date, the set of options available under “Environmental-cracking” should be modified by removing “Stress Corrosion Cracking,” which should be returned to part G1.

Part G5 has a section for environmental cracking information. A review of incident data for 2010 and later shows that the field for stress corrosion cracking (SCC) has zero entries. Instead, operators appear to note SCC as a comment in part G1 for some submitted external corrosion data.

SCC was moved to part G5 only in the last revision to the Incident Report. Prior to that, SCC was included in Part G1, and SCC should be returned there. As a failure mechanism, SCC is time dependent and more related to corrosion than material.

Incident Report: 192.619 MAOP Determination

Reporting the manner used to determine MAOP, a requirement eliminated in the 2010 revision to the Incident Report, should be reinstated.

Incident Reports prior to 2010 required that operators provide information on how MAOP was determined. Based on 2002-2009 incident data, approximately 130 incidents showed MAOP was based on 619(c) and 190 incidents based on 619(a). This data requirement was eliminated in 2010. Information on how MAOP was determined is valuable to identify issues and trends within the population data collected through the Annual Report, and the Incident Report should be modified to start collecting this information again.

Incident Report Definitions

For certain key terms, the Incident Report or the instructions for completing it should adopt definitions that are used generally by the natural gas pipeline industry.

INGAA suggests that clarification be added to some terms used in the instructions for the Incident Report.

- *Explode.* PHMSA should provide a better distinction between explode and ignite. Explode has a connotation of containment that has been compromised in a violent manner and significant energy has been released (Section A-15 and A-17).
- *Rupture.* PHMSA should include the words “burst,” “split” and “break” when describing a rupture (Section C-6).
- *Shutdown.* PHMSA should clarify the shutdown means the pipeline is isolated or the equipment is stopped and that the facility is not blown down (Section A-15).

Conclusion

As the parties who will be subject to the regulations that emerge from the results of these reports, INGAA's members are acutely aware that the reports have to gather all the needed data and do so accurately. The changes identified in these comments, led by adopting INGAA's FFS process in lieu of proposed Annual Report parts Q and R, are critical to ensure that regulations rest on an accurate understanding of the industry, and, in particular, the efforts INGAA's members are making and will continue to make to honor their commitment to the goal of zero incidents.

Respectfully submitted,

/s/

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ATTACHMENT 1: Fitness for Service White Paper

*Draft Work In Progress
Awaiting Stakeholder Input*

White Paper

Definition and Application of Fitness For Service to Gas Pipelines

INGAA Integrity Management
Continuous Improvement
Work Group 4
May 31, 2012



Interstate Natural Gas
Association of America

Definition and Application of Fitness For Service to Gas Pipelines

What Is Fitness for Service (FFS)?

FFS is the ability of a system or component, in this case a pipeline system or portion thereof, to provide continued service, within established regulations and margins for safety, until the end of some desired period of operation or scheduled inspection and reassessment. FFS is a well-accepted approach to evaluate flaws that may be injurious to integrity in equipment, including pipelines, to determine acceptability for continued operation. The FFS approach is used extensively throughout the world in transportation, energy, construction and many other industries since the 1980s.

FFS evaluations for pipelines rely on a detailed threat assessment, risk analysis, the selection of appropriate inspection techniques, and flaw acceptance criteria. Results from FFS evaluations provide guidance on equipment inspection intervals and shape decisions to operate, repair, monitor, or replace equipment.

FFS was the key criteria behind the development of the first ASME B31.8 consensus standards. Through prescriptive recommendations, those initial standards laid out how a pipeline should be designed, constructed, operated and maintained so the pipeline could be judged fit for service. Eventually, PHMSA and its predecessors imported many of these practices into 49 CFR Part 192 as the Minimum Pipeline Safety Standards in effect today. Subsequent ASME editions modified and improved the initial standards and methods. The most recent version, ASME B31.8S, is the latest step in improving FFS.

Implementing the FFS process will require time to evaluate pipelines in a prioritized manner, manage customer service impacts and implement necessary actions. The paper addresses how to start applying the process and extend it over time.

What Data and Information Do FFS Evaluations Rely On?

FFS evaluations employ a review of historical performance, among other things, to identify threats that have and could pose a risk to the safe operation of the facility. Technical analyses, including stress analysis and fracture mechanics, are then employed to evaluate each of the threats and the associated physical flaws (for example, metal loss, cracks, dents, deformations and conditions such as outside/dynamic loads).

Have FFS Evaluations Been Applied in Other Industries?

The methods currently used in FFS evaluations have been applied in the petroleum refining, petrochemical, pulp and paper and the nuclear, coal and gas-fired electric power industries since the 1980s. One of the first acknowledged threat specific applications was actually in the pipeline industry with the development of B31G, a method for calculating the remaining strength of pipelines in areas with metal loss, first published in 1984.

In the absence of federal regulations covering analysis of complex systems, subject matter experts across a number of these industries decided to create a compendium of the methods to
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address a breadth of defect types in the late 1990s. The document was first published in 2000, as American Petroleum Institute (API) Recommended Practice (RP) 579. It was updated in 2007 through a joint effort between API and ASME and published as API RP 579-1/ASME FFS 1.

API RP 579-1/ASME FFS 1 provides for three levels of analysis based on the amount of available data, depth of knowledge, and the degree of conservatism desired:

- Level 1 is used for rapid evaluation, requires the least number of measurements, the few key parameters, and is quite conservative, i.e., it provides for a relatively large safety factor.
- Level 2 requires a deeper analysis and therefore more measurements to establish the actual remaining cross sectional area. It is generally less conservative than Level 1 because of the additional knowledge and information required to conduct a deeper engineering analysis.
- Level 3 relies on stress analysis to provide an even more in-depth examination of metal loss. Level 3 requires an intensive quantification of measurement, loading stresses, and material properties, to meet the detailed needs of a finite element analysis.

The widespread acceptance and use of API RP 579-1/ASME FFS 1 demonstrates the well-established precedence of successfully applying the principles of FFS for verifying the mechanical integrity of pipelines.

Is Evaluating FFS Different for the Pipeline Industry?

Yes and no. The process is the same, but the setting is not. In every other industry where FFS evaluations are applied, the equipment being evaluated is generally within a fence line and often above ground. This means that the environment around the equipment including piping can readily be monitored and quite often controlled.

FFS evaluations for pipelines are different in that they rely on a detailed threat assessment, risk analysis, selection of appropriate inspection techniques, and acceptance criteria for non-injurious defects.

Where other facilities subject to FFS assessment generally are accessible and geographically contained, pipelines typically are buried, traversing linearly through the countryside, passing through a variety of soil types and geological conditions while encountering flooding, storm damage and other environmental challenges. Burying minimizes some environmental threats, but burying also subjects pipelines a variety of ground movements such as subsidence, vibration effects and even damage through direct contact and disturbance from excavation work.¹ Evaluating a pipeline's FFS thus requires an operator not only to understand threats to

¹ While the NTSB concluded that pipe bursting activities nearby the transmission line did not contribute to the San Bruno failure, the fact that it was the subject of significant fact gathering and analysis in their investigation provides a key lesson learned: Pipeline operators must be aware of excavation and construction work around their facilities. Of equal importance, entities planning to work around underground facilities, including pipelines, must contact One Call, which was done for work in San Bruno.

integrity, but also to assess a pipeline environment spanning tens, hundreds and often thousands of miles.

Risk assessment is essential in prioritizing and managing preventive and mitigation measures. A complete understanding of the threats to integrity is essential including the potential contribution of the surrounding environment. Risk assessment is most effective when available data, including data specific to individual operating environments, is examined as an integrated whole. FFS evaluations use data from assessments, as well as from routine maintenance activities, often to identify areas warranting further investigation through excavation and inspection. FFS methods are used in these excavations to evaluate fitness based on a pipeline segment's actual, as-found condition.

Assessment tools and engineering methods are imperfect, so an operator will integrate the data collected during an excavation with other information (such as coating condition and as-found pipe to soil potentials) to form the analytical foundation for making decisions on preventive and mitigation measures. Finally, as part of a continuing desire to improve processes and achieve the target of zero incidents, the as-found conditions and results of evaluations are fed back into the threat assessment and risk analysis processes. Lessons learned from the findings and analyses are shared throughout the organization and, where applicable, throughout the industry.

Examples of FFS Evaluations for Metal Loss/Corrosion, Dents and Deformations

The corrosion evaluation method, ASME B31G, is a Level 1 type method. It is used for rapid evaluation of a concern; it requires data for just a few key parameters; and it is quite conservative in that it provides for a relatively large safety factor. RSTRENG applied in two-parameter mode (using length and depth) is also a Level 1 method. RSTRENG applied using a metal loss profile (sometimes referred to as a “river bottom” analysis) is a Level 2 method. API RP 579-1/ASME FFS 1, described above, provides Level 3 methods as well.

Pipeline operators also apply a variety of techniques to assess a pipeline segment's physical condition. In-line inspection (ILI) with high-resolution magnetic flux leakage sensors are used to identify and characterize metal loss. High-resolution geometry sensors are used to identify and characterize deformations in pipelines.

The FFS evaluation results in an estimate of a segment's remaining strength, which can be characterized by a predicted failure pressure ratio. Operators use the predicted failure pressure ratio, a measure of the margin above the MAOP, and the calculated pipeline strains to determine whether to excavate and the timing of excavations. Where an excavation is made to evaluate the metal loss, an indentation or both, FFS methods are then applied using actual measurements to determine a safe operating pressure. These comparative measurements are then used to improve ILI technology. Where excavation is not warranted, the operator uses the predicted failure pressure ratio to define an interval where the segment will be monitored pending the next assessment.

It is important to understand that operators do not rely simply on one measure or one tool. The corrosion control methods in ASME B31.8, which are in large part incorporated into 49 CFR 192 Subpart I, provide for “layers of protection” from failure. The concept of “layers of protection analyses” or LOPA was first described in the chemical industry in the mid-1990s. It was recognized as a way of demonstrating while failures are so infrequent, while assessing the rare

failures both to diagnose what occurred and to identify measures to prevent recurrence. LOPA was first captured in a book entitled, Inherently Safer Chemical Processes, published by the Center for Process Safety (part of the American Institute of Chemical Engineers). LOPA approach “designs in” redundancy, so failure is prevented even if one layer of defense is weakened or lost.

FFS Applied to Environmental-Related Cracking

There are FFS methods available for evaluating environmental-related cracking, including stress corrosion cracking (SCC). SCC direct assessment (DA) prioritizes locations along the pipeline for investigative excavations. Nondestructive evaluations and measurements on the exposed pipe provide the inputs for FFS evaluations that estimate a segment's remaining strength and predicted failure pressure ratio. As was the case with metal loss and indentations, the operator uses the results of the FFS evaluation to determine whether to excavate and, where there is a sufficient margin of safety, to define a future interval to the next assessment.

FFS Applied to Pre-Regulation Pipe

There are approximately 179,000 miles of on-shore natural gas transmission pipe installed prior to pipelines safety regulations (1970) out of a total 300,000 miles. INGAA operates approximately two-thirds of the total mileage.

A process was developed to address the FFS of pre-regulation pipe (pipe installed before March 12, 1970) given 1) concerns raised by the Pipeline and Hazardous Materials Safety Administration (PHMSA) in their January 4, 2011 Advisory Bulletin, 2) recommendations issued by the National Transportation Safety Board (NTSB) following their investigation of the Pacific Gas and Electric Incident in San Bruno, California, and 3) requirements in Section 23 of the recently enacted pipeline safety legislation, Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011.

The FFS process is best managed by way of following a flow or process diagram through a series of screening steps and decision gates (Figure 1, at the end of this section, below). The text that follows provides a description of how one (referred to as an “operator”) systematically works through the decision process. The process, as depicted in Figure 1 is designed to make use of existing pressure test and other records and where records do not exist, through demonstrating a historical pressure test (see inset below for background on pressure testing). Where records or pressure testing are inadequate, the process moves the operator in a direction such that each decision becomes more and more conservative.

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Improvement Process for Traceable, Verifiable and Complete Records

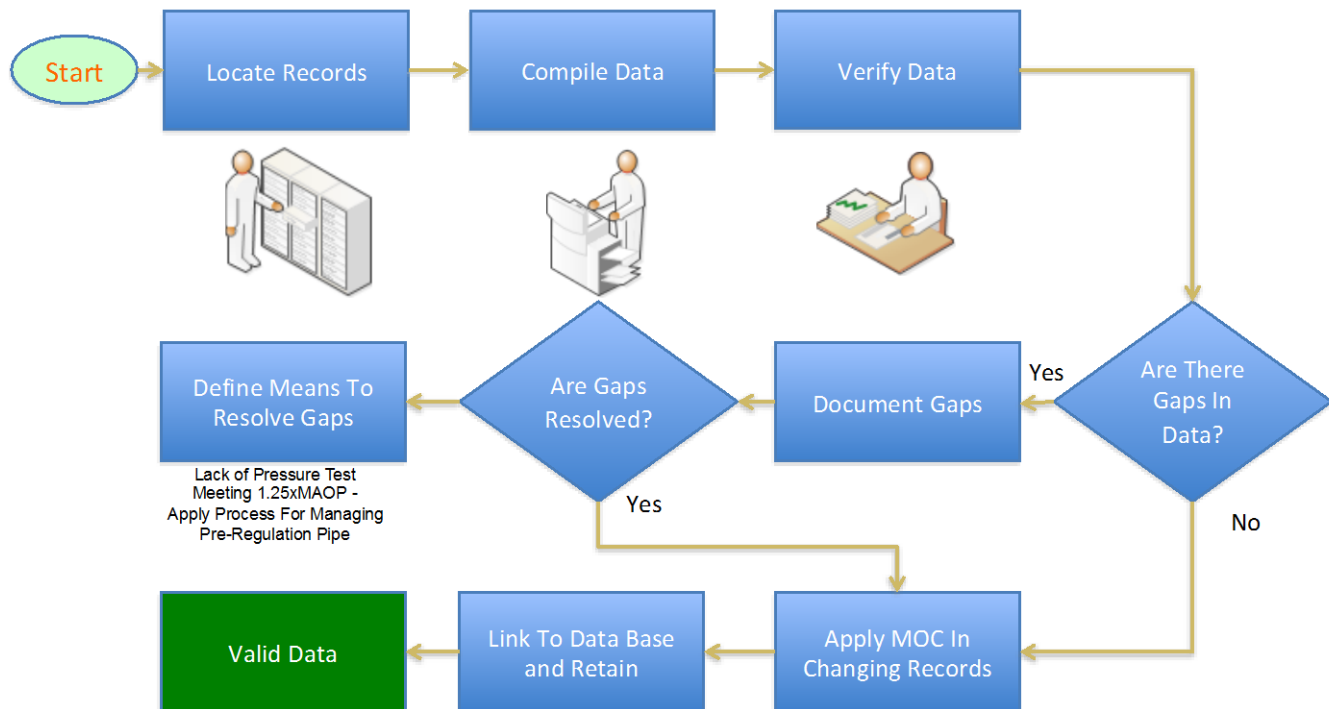


Figure 1 – Improvement Process for Traceable, Verifiable and Complete Records

Overview of the Process

The FFS process is best managed by way of following a flow or process diagram through a series of screening steps and decision gates (Figure 2, at the end of this section, below). The text that follows provides a description of how one (referred to as an “operator”) systematically works through the decision process. The process is designed to make use of existing pressure test and other records and where records do not exist, through demonstrating a historical pressure test (see inset below for background on pressure testing). Where records or pressure testing are inadequate, the process moves the operator in a direction such that each decision becomes more and more conservative.

At a high level there are eight cases addressed by the process. They are:

1. Pipe segments in **HCAs, Class 3 or 4 that have a strength test to at least 1.25xMAOP** can continue to operate under 49 CFR 192, subject to the Continual Evaluation requirements of 49 CFR 192.937.
2. Pipe segments in **HCAs, Class 3 or 4 that have a strength test to at least 1.1xMAOP that are piggable** can:
 - a. Conduct a pressure test to 1.25xMAOP,
 - b. Run ILI that identifies and characterizes long seam and pipe body anomalies,
 - c. Reduce pressure to 80% of the established MAOP or
 - d. Replace the pipe not meeting these conditions.
3. Pipe segments in **HCAs, Class 3 or 4 that have a strength test to at least 1.1xMAOP that are not piggable or those that do not have a strength test of at least 1.1xMAOP** can:
 - a. Conduct a pressure test to 1.25xMAOP,
 - b. Reduce pressure to 80% of the established MAOP or
 - c. Replace the pipe not meeting these conditions.
4. Pipe segments in **Class 1 or 2 that have a strength test to at least 1.1xMAOP that do not contain pipe with known long seam issues** can continue to operate under 49 CFR 192.
5. Pipe segments in **Class 1 or 2 that contain pipe with known a history of long seam issues that are also piggable** can:
 - a. Run ILI that identifies and characterizes long seam and pipe body anomalies,
 - b. Conduct a pressure test to 1.25xMAOP,
 - c. Reduce pressure to 80% of the established MAOP or
 - d. Replace the pipe not meeting these conditions.
6. Pipe segments in **Class 1 or 2 that contain pipe with known a history of long seam issues that are non-piggable segments** can:
 - a. Conduct a pressure test to 1.25xMAOP,
 - b. Reduce pressure to 80% of the established MAOP or
 - c. Replace the pipe.
7. Pipe segments in **Class 1 or 2 that contain pipe with no known history of long seam issues** can continue to operate under 49 CFR 192, subject to the Continual Evaluation requirements of 49 CFR 192.937.
8. Pipe segments that are **not HCAs, Class 3 or 4, operating below 30% SMYS** can continue to operate under 49 CFR 192, subject to the Continual Evaluation requirements of 49 CFR 192.937.

The technical basis for these outcomes is described below. An operator can always choose to conduct a 49 CFR 192, Subpart J pressure test and demonstrate fitness to operate at its MAOP.

Starting The Process

The process begins with a question about what year the pipeline segment was installed (Figure 2 (end of paper), Diamond 1). Pipe installed on or after March 12, 1970, became subject to new regulatory requirements for design and construction, which required FFS testing by way of a pressure for establishing MAOP. Pipe installed prior to that date was not subject to the regulatory requirements.

If the answer is “Yes”, i.e., the segment, was installed prior to March 12, 1970, then the operator moves to a question, Was Segment Pressure Tested? (Diamond 2). If the answer is “No”, then proceed to **B** on the second page of the flow chart. If the answer is “Yes”, which means a pressure test was conducted, the process proceeds through a series of questions to determine what kind of testing was conducted and what level of assurance is provided by that testing.

Historical Pressure Testing

The series of questions in Diamonds 3, 4 and 5 are set up to determine what type of pressure testing was done. Questions that address the level or intensity of the pressure test are addressed subsequently in Diamonds 6 and 7.

Was A Field Installation Pressure Test Conducted?

The process first raises the question, was a field installation pressure test, i.e., was there a pressure test at the time of installation of the pipe (Diamond 3)? If the answer is “Yes”, the operator goes to Diamond 6. If the answer in Diamond 3 is “No”, the operator moves to Diamond 4, which asks if a post-installation test was conducted.

Was A Post Installation Pressure Test Conducted?

The process then raises the question, was there a post installation pressure test?, i.e., was there a pressure test conducted at some point after installation of the pipe? (Diamond 4). If the answer is “Yes”, the operator goes to Diamond 6. If the answer in Diamond 4 is “No”, the operator moves to Diamond 5, which asks if a test was conducted in the mill, i.e., the manufacturing complex often referred to as a pipe mill or more simply a “mill”.

Background on Pressure Testing

ASME B31.8 included use of an installation field pressure test beginning in the 1955. The 1967 edition of B31.8, Section 841.14 requires a test to at least 85 percent of mill test pressure if the mill test pressure was less than 85% SMYS. There were operators using pressure testing on pipe at the time of pipeline installation as early as 1942 following ASA B31.1-223.

The initial research that established the use of a 1.25 safety factor between the test pressure and the maximum operating allowable pressure was conducted by Duffy and others at Battelle.¹ The authors stated “In view of the evidence discussed in this report, it is recommended that the allowable operating pressure be set at 80 percent of the minimum hydrostatic proof test pressure level when a high test pressure is used – specifically when the minimum test pressure is equal to 90 percent of the minimum specified yield strength or higher.”

PHMSA’s predecessor agency, the Research and Special Programs Administration (RSPA), issued an advisory on low-frequency electric resistance welded (LF-ERW) pipe following a number of incidents, primarily on hazardous liquid pipelines. RSPA issued an Alert Notice on January 28, 1988.² The alert notice stated, “All operators who have pre-1970 ERW pipe in their systems should carefully review their leak, failure, and test history as well as their corrosion control records to ensure that adequate cathodic protection has been and is now being provided. In areas where cathodic protection has been deficient for a period or periods of time, the operators should conduct an examination of the condition of the pipeline, including close interval pipe-to-soil corrosion surveys, selective visual examination of the pipe coating, and/or

other appropriate means of physically determining the effects of the environment on the pipe seam. If an unsatisfactory condition is found, or if a pre-1970 ERW pipeline has not been hydrostatically tested to 125% of the maximum allowable pressure, operators should consider hydrostatic testing to assure the integrity of the pipeline.” RSPA issued a second Alert Notice in March 1989 expressing continued concern over failures on LF-ERW seams.³ This notice recommended hydrostatically testing all hazardous liquid pipelines containing LF-ERW that had not been hydrostatically tested to 1.25xMOP, or alternatively, reduce the operating pressure 20 percent. Some natural gas transmission operators are known to have pressure tested pipeline segments containing pre-1970 ERW line pipe as a result of these notices.

Strength Test Portion of a Pressure Test

The strength test, sometimes referred to, as a “proof test”, is the initial portion of a pressure test that is conducted to a desired level to establish or provide “proof” of the strength of the pipe. Pressure tests conducted on pipe as installed or at some time after construction also typically have an additional portion of the test, referred to as a “leak test”. This portion of the test, as the name denotes, is used to detect and to confirm that leaks may have occurred, as will be indicated by a drop in pressure. The drop in pressure may be gradual if the leak is small. By contrast, if a test failure in the pipe results in a rupture, the pressure will fall rapidly. Water leaking from a failure will be found near the pipe perforation.

The duration of the ‘Proof’ portion of the pressure test is typically the time required for the pressure to stabilize in the test section. The duration is a function of test section length, elevation change and temperature. Typically the segment is stabilized within 30 minutes to an hour.

In a report prepared for GRI in 2001, Eiber and Leis stated “Strength re-tests of pipelines should be conducted using high pressures (90 to 110% SMYS) and held for 30 minutes at maximum pressure. The pressure should then be decreased to 90% of the test pressure and held for as long as necessary for a leak check. This will eliminate defect growth during the leak check and minimize growth during the pressure test.”⁴

In a paper at IPC in 2004, Brian Leis stated that, “It is emphasized that a one-hour long hold at maximum pressure remains a viable upper bound for typical ductile line pipe. As this hold time also leads to ductile tearing along the tips of the larger defects remaining in the pipeline, care must be to select the hydrotest parameters consistent with the purpose of the test and the properties of the line pipe body and seam.”⁵

The 2010 edition of B31.8 requires a pressure test to 1.25 times MAOP in Class 1 and 2 locations. This change was a result of research and industry practice as outline in several studies as discussed above. This level of testing also matches the B31.4 requirements for hazardous liquid pipelines; however, class location is not used in that code, all pipe is tested to a minimum of 1.25 times MAOP.

In a manufacturing mill, a pipe joint, typically 40 feet in length, is tested for approximately ten seconds. This is the time needed to stabilize the pressure within the pipe joint. Pipe with a sufficiently large flaw in the pipe body or long seam that does not have sufficient strength will fail at the test pressure. The higher the test pressure, the smaller the flaw size required to fail the test. A field pressure test on multiple miles of installed pipe takes a longer period to stabilize.

As stated above, the time required to stabilize a long field test segment is a function of the segment length but is typically 30-60 minutes. The same principle applies to the single pipe joint in the mill; as soon as the pressure is stabilized at the desired level, the strength is established or the pipe fails. Therefore, the short duration mill test is as effective as a strength and leak test for the purpose of establishing fitness for service for the long seam and pipe body as a field pressure test.

Was A Mill Pressure Test Conducted?

The process raises the question, was there a pressure test conducted at the pipe manufacturing mill?, i.e., was there a pressure test in the mill for each joint of pipe? (Diamond 5). If the answer is “Yes”, the operator goes to Diamond 7. If the answer in Diamond 5 is “No”, the operator moves to **B**, a risk based alternative, on the second page of the flow chart.

The mill test is considered in this process because every joint of pipe made to API 5L Specification for Line Pipe had to be hydrostatically tested since the first edition of API 5L, Specification for Line Pipe was published in 1928.⁶

Pressure Testing Level

Where a pressure test was conducted at original installation or at some later time, the next step in the process is to determine whether the test meets a level of 1.25xMAOP. This level was selected to screen out pipe from further analysis and evaluation based on NTSB Recommendation P-11-15. From an engineering standpoint, this establishes an adequate safety margin above the maximum operating pressure. Note that lower test pressures may also be acceptable under certain conditions, but the 1.25xMAOP test level has been shown and accepted by virtually all studies and safety and regulatory authorities as adequate under all conditions.

The question of test level is applied to pipe that was either tested at installation or subsequently in Diamond 6, which asks if the pipe was tested to a level of 1.25xMAOP or greater? If the answer is “Yes”, the pipe meets the intent of the NTSB recommendation and is routed to **A**.

A stipulates that the pipe is operated and maintained under 49 CFR 192. If the answer in Diamond 6 is “No”, the operator moves to Diamond 8, which asks if the segment contains pipe that has a weld seam types known to be have experienced integrity issues. The seam types include low-frequency electric resistance welded (LF-ERW), direct-current electric resistance welded (DC-ERW), electric fusion or flash welded, furnace butt-welded, and lap welded.

In Diamond 7, the question is posed, was the mill test at least equivalent to 1.25xMAOP? The question uses 1.25xMAOP equivalence to keep the testing level at the same level as a field test. For Class 1 pipe to be operated at 72% SMYS, a mill test to 90% is equivalent to 1.25xMAOP. For Class 2 pipe to be operated at 60% SMYS, a mill test to 75% is equivalent (API 5L required an 80% SMYS test starting in 1931 so tests on Class 2 pipe manufactured under 5L editions in effect since that time meet the 1.25xMAOP equivalence). For Class 3 pipe to be operated at 50 %SMYS, a mill test of at least 62.5%SMYS provides equivalence.

Diamond 8 asks if the segment contains pipe that has a weld seam types known to be have experienced integrity issues. The seam types include low-frequency electric resistance welded (LF-ERW), direct-current electric resistance welded (DC-ERW), electric fusion or flash welded, furnace butt-welded, and lap welded. If the answer is “Yes”, the pipe contains one of the identified long seam weld types and has not had a test to 1.25xMAOP, and is routed to a risk based alternative, indicated in Figure 2 by **B**.

If the answer in Diamond 8 is “No”, the pipe does not have the identified long seam types and was not tested to 1.25xMAOP. The operator is routed to Diamond 9.

Diamond 9 asks if a pressure test to 1.1xMAOP was conducted at installation or sometime during the life of the segment. If the answer is “No”, the operator is routed to the risk-based alternative, **B**. If the answer to the question in Diamond 9 is “Yes”, i.e., the pipe segment has undergone a 1.1xMAOP pressure test, Class 1 in that segment is routed to **A**. While this test level does not meet the literal expectation of NTSB Recommendation 11-15, line pipe in Class 1 not containing the identified long seam types, tested to at least 1.1xMAOP, has operated safely since these tests were first used.

Risk-Based Evaluation Of Certain Pre-Regulation Pipe (B) And Use of ILI In Lieu of Pressure Testing

Pipeline segments that follow the path to B in the application of this FFS process are treated through a more detailed evaluation, shown on page 2 of Figure 2 of the process. This portion of the process draws upon the approach developed for previously untested hazardous liquid pipelines in the 1990s. The specific regulatory requirements are found at 49 CFR 195.303. The basis of the risk-based approach is the close proximity to population. In addition, the approach allowed for the use of ILI assessments in lieu of a pressure test. Similarly, the same approach is being proposed for natural gas transmission pipeline systems. As an added benefit of employing ILI, anomalies can be found that are smaller than the largest defect that would just fail a pressure test. HCAs and class locations serve as the means of helping calculate risk by prioritizing probability of consequences while ILI is used to prioritize the probability of failure.

HCAs

The highest priority segments are HCAs and these are identified in Diamond 10, which asks if the segment is an HCA? If the answer is “No”, then the operator moves to Diamond 13, which asks if the segment is Class 3 or 4? If the answer in Diamond 10 is “Yes”, the operator moves to Diamond 11, which asks if a strength test was conducted to 1.25xMAOP? If the answer is “Yes”, that is, the segment was tested to at least 1.25x MAOP, then the operator goes to L, which indicates that the pipe continues to be operated under 49 CFR 192, and in addition, 49 CFR 192.937 is applied. The intent is to apply continual evaluation, including past and present integrity assessment results, data integration and risk assessment information, and decisions about remediation and additional preventive and mitigative actions. It is also intended that the operator use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

If the answer in Diamond 11 is “No”, a strength test of 1.25x MAOP was not achieved and the operator moves to Diamond 12. Diamond 12 poses the question of was a strength test of 1.1xMAOP conducted? The “No” answer out of Diamond 12 requires that the operator conduct a pressure test to 1.25xMAOP, reduce pressure to 80% of the established MAOP or replace the pipe not meeting these conditions.

If the answer in Diamond 12 is “Yes”, i.e., a 1.1xMAOP strength test was conducted, then the operator goes to Diamond 17. The safety margin of 1.1 is used today for pipelines in areas where there is not an abundance of population nearby. While the strength test in this instance does not meet the 1.25xMAOP recommended by NTSB, the approach is to ensure that the segment has a safety margin above the MAOP, and in addition, ILI will be applied to identify and characterize flaws such as long-seam weld anomalies that would pose a threat to integrity.

Identification of long seam weld anomalies requires use of transverse-oriented magnetic flux leakage (MFL) technology on an ILI tool. Electromagnetic-acoustic transducer (EMAT) technology has been shown to provide additional data to supplement MFL technology for seam weld assessments. Alternatively, ultrasonic technology (UT) can be used; however, there has been limited application of EMAT and UT technologies for seam weld assessment on natural gas transmission pipelines. The transverse-oriented technology is available only in selected diameters. UT requires use of a liquid couplant, making their applicability limited. INGAA members are working with the American Gas Association, ILI providers and research organizations such as the Pipeline Research Council International and the Gas Technology Institute to improve the identification and characterization of long seam anomalies that would pose a threat to integrity by taking advantage of multiple technologies. It is anticipated that the technologies and their analysis processes will continue to improve during the timeframe in which HCAs are being addressed and operators begin to address Class 3 and 4 pipe.

Diamond 17 poses the question of whether or not the segment is piggable. If the segment is piggable then the operator goes to M. The operator can run ILI that identifies and characterizes long seam and pipe body anomalies, reduce pressure to 80% of the established MAOP, or replace the pipe not meeting these conditions. Conceivably, an operator could elect to conduct a pressure test to 1.25xMAOP instead of using ILI.

If the answer in Diamond 17 is “No”, i.e., the segment is not piggable, the operator goes to H and can conduct a pressure test to 1.25xMAOP, reduce pressure to 80% of the established MAOP, or replace the pipe not meeting these conditions.

Class 3 or 4

Class 3 or 4 segments are identified in Diamond 13, which asks if the segment is in Class 3 or 4? If the answer is “No”, then the operator moves to Diamond 14, which asks if the segment is operated at greater than 30% SMYS? If the answer is “Yes” in Diamond 13, the operator moves to Diamond 11, which asks if a strength test was conducted to 1.25xMAOP? The operator will proceed from Diamond 11 as above for HCAs.

Pipe Segments Operated At Less Than 30% SMYS

Diamond 14 poses the question of whether or not the segment is operated at a level greater than 30% SMYS. The level of 30% SMYS was selected as it is generally accepted to be the “low stress” boundary between leaks and ruptures for likely pipeline defects⁷. The basis of this approach is that preventing ruptures represents a much higher consequence priority than leaks on transmission pipelines. Leaks are important and will be discussed below. In applying the 30% SMYS threshold, operators need to recognize that the threshold presumes an understanding of the minimum level of toughness and the knowledge of pipe diameter, wall thickness and other metallurgical properties such as the grade of pipe. Operators are

encouraged to refer to the reference above to evaluate whether adjustments should be made to the 30% threshold level for the pipe segment being evaluated.

If the answer in Diamond 14 is “No”, the segment can continue to operate under 49 CFR 192, subject to the Continual Evaluation requirements of 49 CFR 192.937. If the answer in Diamond 14 is “Yes”, the operator proceeds to Diamond 15.

Diamond 15 poses the question of whether or not the segment contains pipe that has a joint factor of less than 1.0 (such as lap-welded pipe, hammer-welded pipe, and butt-welded pipe) or if the pipeline is composed of LF-ERW, DC-ERW, electric fusion or flash-welded, and if the answer is “Yes”, a manufacturing threat is considered to exist.

If the answer in Diamond 15 is “No”, i.e., the segment does not contain the pipe identified above as specified in B31.8S, Appendix A-4, and the segment can continue to operate under 49 CFR 192, subject to the Continual Evaluation requirements of 49 CFR 192.937.

If the answer in Diamond 15 is “Yes”, the operator proceeds to Diamond 16, which poses the question of whether there is a history of long-seam related failures for that mill production run of pipe used in the segment. If there has not been a prior failure history for this pipe on the segment, the operator can go to M and run ILI that identifies and characterizes long seam and pipe body anomalies, reduce pressure to 80% of the established MAOP, or replace the pipe not meeting these conditions.

If the answer in Diamond 16 is “Yes”, i.e., there has been a history of long-seam failures on the segment, the operator proceeds to Diamond 17 (discussed above) and follows the same path.

If the answer in Diamond 17 is “Yes”, the operator goes to M and can run ILI that identifies and characterizes long seam and pipe body anomalies, reduce pressure to 80% of the established MAOP, or replace the pipe not meeting these conditions. If the answer in Diamond 17 is “No”, then the operator goes to H and conducts a pressure test, reduces the operating pressure, or replaces the pipe.

Timeframe For Implementation

INGAA members are committed to completing the FFS process for HCAs by 2020 and segments in Class 3 and 4 on a risk-prioritized basis using the experience gained in HCAs as a next step. The FFS also process establishes a framework for segments beyond HCA's, Class 3 and 4, and the timeline for implementation in those areas would occur after the higher priority segments in a risk-prioritized manner, incorporating lessons learned during the earlier implementation of the process.

Conclusions

The paper addresses background on FFS, how to start applying the FFS process for pre-regulation pipe and extend it over time. The FFS process prioritizes the right place to start as pipelines within HCAs that have incomplete strength test records. The testing, repair, remediation or replacement of these pipelines within HCAs will be accomplished over a defined time frame, and during that period findings will be continually evaluated to derive lessons learned for future work. Implementing the FFS process will require time to evaluate pipelines in a prioritized manner, manage customer service impacts and implement necessary actions.

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Jan 12, 2012

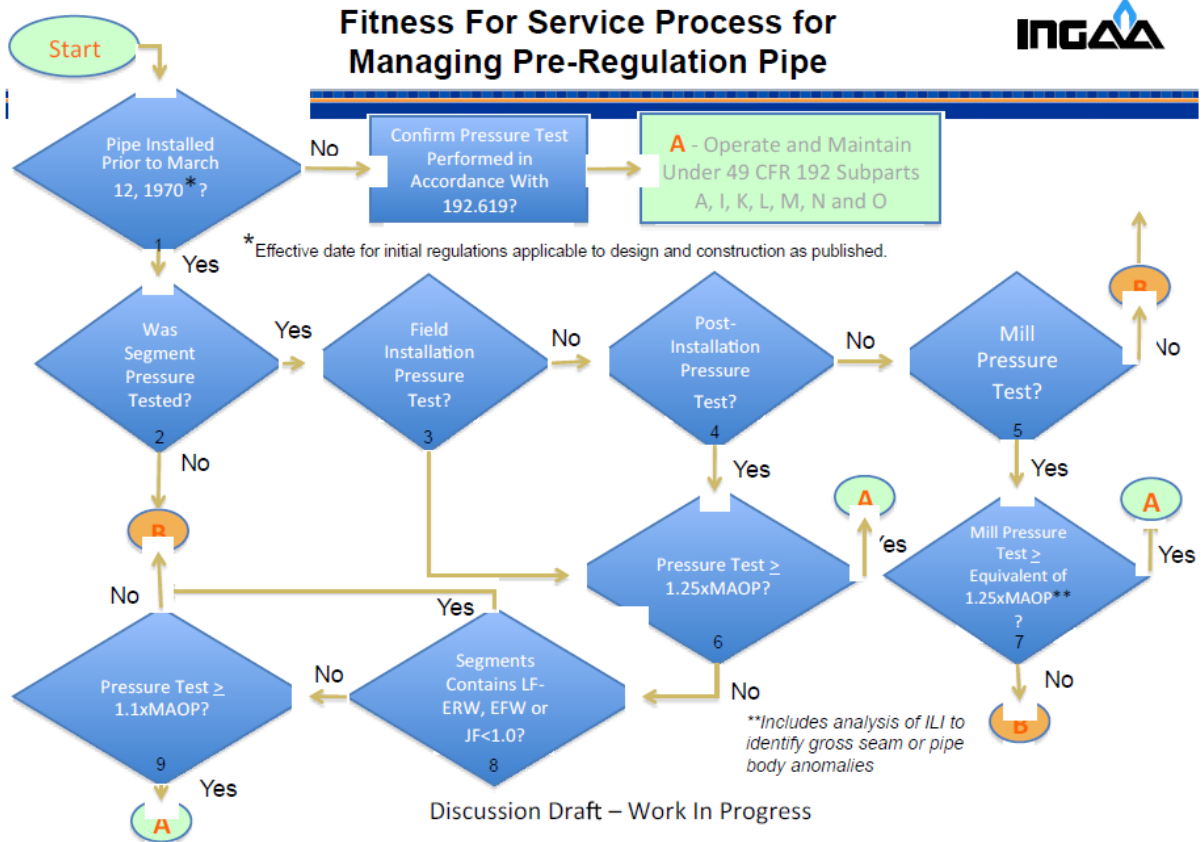


Figure 2 – Fitness for Service Process for Managing Pre-Regulation Pipe

Jan 12, 2012

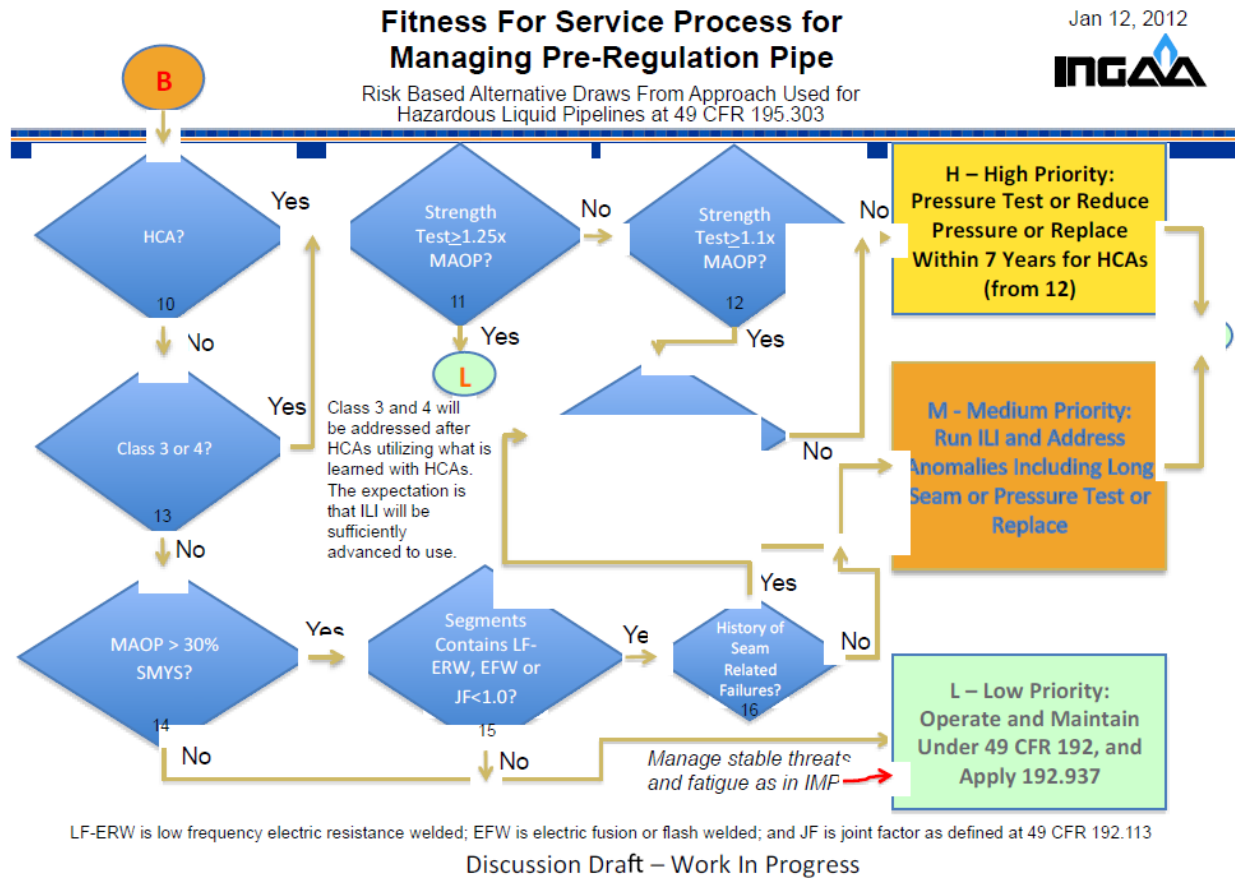


Figure 2 – Fitness for Service Process for Managing Pre-Regulation Pipe (Continued)

ATTACHMENT 2: INGAA Substitute Parts Q and R

Part Q - Gas Transmission Miles by § 192.619 MAOP Determination Method

[illegible]

Part R (1) - Gas Transmission Miles 125% MAOP Pressure Test and Instrumented Inspection Device Passage (pipe installed prior to the effective date of the regulations, March 12, 1970)

	Miles with MAOP >30% SMYS which have not been subjected to a post-construction hydrostatic pressure material strength test of at least 125% of the MAOP		Miles with MAOP <= 30% SMYS which have not been subjected to a post-construction hydrostatic pressure material strength test of at least 125% of the MAOP	
Location	Not able to accommodate the passage of instrumented internal inspection devices	Able to accommodate the passage of instrumented internal inspection devices	Not able to accommodate the passage of instrumented internal inspection devices	Able to accommodate the passage of instrumented internal inspection devices
Class 1 (in HCA)				
Class 1 (not in HCA)				
Class 2 (in HCA)				
Class 2 (not in HCA)				
Class 3 (in HCA)				
Class 3 (not in HCA)				
Class 4 (in HCA)				
Class 4 (not in HCA)				
Total				

Part R (2) - Gas Transmission Miles 110% MAOP Pressure Test and Instrumented Inspection Device Passage (pipe installed prior to the effective date of the regulations, March 12, 1970)

	Miles with MAOP >30% SMYS which have not been subjected to a post-construction material strength test of at least 110% of the MAOP		Miles with MAOP <= 30% SMYS which have not been subjected to a post-construction material strength test of at least 110% of the MAOP	
Location	Not able to accommodate the passage of instrumented internal inspection devices	Able to accommodate the passage of instrumented internal inspection devices	Not able to accommodate the passage of instrumented internal inspection devices	Able to accommodate the passage of instrumented internal inspection devices
Class 1 (in HCA)				
Class 1 (not in HCA)				
Class 2 (in HCA)				
Class 2 (not in HCA)				
Class 3 (in HCA)				
Class 3 (not in HCA)				
Class 4 (in HCA)				
Class 4 (not in HCA)				
Total				

Note: Material strength test identified in Section 23 of Pipeline Safety Act of 2011

