Integrity Verification Process Workshop – August 7, 2013 – FAQs

These Frequently Asked Questions (FAQs) are intended to clarify, explain, and promote better understanding of the proposed Integrity Verification Process. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing regulations and standards. Requests for written interpretations regarding the applicability of one or more of the pipeline regulations to a specific situation may be submitted to PHMSA in accordance with 49 C.F.R. § 190.11.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) and the National Association of Pipeline Safety Representatives (NAPSR) sponsored a public workshop on a proposed Integrity Verification Process (IVP). The IVP Workshop was held on August 7, 2013 at The Westin Arlington Gateway in Arlington, Virginia. The IVP Workshop was held as part of PHMSA's effort to address the Congressional mandate set forth in Section 23 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pub. L. 112-90) and three National Transportation Safety Board (NTSB) recommendations to PHMSA from the San Bruno, California pipeline rupture (NTSB P-11-14 "Delete Grandfather Clause", NTSB P-11-15 "Seam Stability", and NTSB P-11-17 "Piggable Lines"). PHMSA presented a preliminary process flow chart at the IVP Workshop as a discussion document but did not make any final determinations on the proposed IVP guidelines at the workshop.

The questions below were received during and after the IVP Workshop from participants, webcast viewers, and other stakeholders.

IVP Workshop FAQs are being posted on the IVP Docket Number PHMSA-2013-0119 at http://www.regulations.gov/#!home and the meeting registration Web site at http://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=91.

1. The Integrity Verification Process (IVP) Workshop comment period closes on September 9, 2013. Can the public comment period be extended?

   Answer:

   PHMSA might consider extending the IVP Workshop comment period if good cause is demonstrated. If and when any rulemaking proceedings in this area are undertaken, there will be extensive opportunity for public comment in such proceedings as well.

2. When does *ex parte* begin for the IVP rulemaking process – after Workshop, September 9 comment period, writing begins for Notice of Proposed Rulemaking (NPRM), or other date?

   Answer:

Under DOT and PHMSA *ex parte* policies, with rare exceptions that are disclosed in the docket, PHMSA generally does not engage in *ex parte* communications once the drafting of any NPRM has begun.

3. Section 23 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act (Pipeline Safety Act) of 2011 specified that MAOP and material records be verified for segments in HCAs and Class 3 and 4 locations that operate at greater than or equal to 30% stress levels. Why is IVP broader in scope?

   Answer:

   Section 23 of the Pipeline Safety Act of 2011 required verification of records for Class 3 and 4 locations and for Class 1 and 2 high consequence areas (HCAs). The IVP is also addressing NTSB recommendations P-11-14, P-11-15, and P-11-17, which are broader and apply to all gas transmission pipelines.

4. Will IVP be a regulatory requirement? If so, what will be the rulemaking process?

   Answer:

   Consistent with Congressional mandates, PHMSA is considering the implementation of IVP into Part 192 regulations under formal rulemaking procedures in the future, likely beginning with a NPRM.

5. Will the IVP result in new regulations for Grandfathered pipe, confirmation of MAOP, verification of records, untested pipe and seam stability to meet Congressional mandates and NTSB recommendations?

   Answer:

   The draft IVP Chart presented at the workshop is the first step in proposing approaches to defining processes and requirements to address the congressional mandates and NTSB recommendations. In accordance with Congressional mandates, PHMSA expects to initiate the process to codify the IVP requirements by publication of an NPRM.

   PHMSA proposes to determine pipe segments that would be subject to new or revised regulations intended to meet the mandates and recommendations by means of

screening criteria related to location (HCAs and MCAs), vintage of pipe (legacy or modern pipe), pressure test history, operating stress level, and the quality of material documentation and MAOP records.

PHMSA proposes to verify integrity through actions such as seam stability evaluation, spike pressure test, seam and pipe body crack assessment, engineering critical assessment, ILI (smart pig or in-line inspection) tool runs for threats such as seam cracks, in-the-ditch nondestructive tests, validation of material properties in cases where historical records are not available, etc.

PHMSA seeks input from stakeholders including public advocates, service providers, industry, and state and federal government on any aspect of the proposed integrity verification process.

6. Does PHMSA want to apply a similar process to hazardous liquid pipelines? Will it be through a rulemaking process?

   Answer:

   After the IVP has been completed for Gas Transmission pipelines, PHMSA will consider rulemaking for hazardous liquid pipelines.

7. Are offshore lines included?

   Answer:

   The proposed IVP process applies only to onshore gas transmission pipelines.

8. Is the plan to expand this to gas gathering lines?

   Answer:

   PHMSA has no plans to expand IVP to gas gathering lines at this time.

9. Is the plan to expand this to gas distribution lines?

   Answer:

   PHMSA has no plans to expand IVP to gas distribution lines at this time.

10. PHMSA's estimate of the amount of pipe that would be subjected to the IVP process seems low.

    Answer:

    The estimates are based upon 2012 Annual Reports. PHMSA will adjust its statistics and estimates as operators submit amended or updated 2012 Annual Report data.

11. Should operators resubmit 2012 Annual Report data if they misunderstood instructions or, in cases where documentation reviews had not been completed, if they reported pipe in certain categories based on conservative assumptions?

    Answer:

    Yes. PHMSA expects operators to update their reports to assure that information submitted is correct and up-to-date to the best of their knowledge.

12. In the 2012 Annual Reports submitted in late June 2013, some pipeline operators may have reported Grandfather Clause, Section 192.619(c), as 192.619(a)(3) 5-year pressure records.

    Answer:

    PHMSA is aware that some operators have reported pipe with MAOP established under Section 192.619(a)(3) that should have been reported as falling under the Grandfather Clause in Section 192.619(c). Operators who have incorrectly reported data in their 2012 Annual Reports should resubmit corrected reports.

13. Should pipeline operators be required to generate records for all pre-1970 pipe to meet 49 Code of Federal Regulations (CFR) Part 192.619 for maximum allowable operating pressure (MAOP) determination?

    Answer:

    Pipeline operators are required by the Code to maintain records that were used to determine MAOP. In addition, PHMSA anticipates that on pipeline segments where MAOP or material documentation records have been lost the integrity verification process would require the implementation of integrity management principles for the evaluation of threats, if they are in a high consequence area (HCA) or moderate

consequence area (MCA) or otherwise meet the proposed screening criteria and that the IVP actions be fully documented.

14. Explain the difference between Sections 192.619(a)(3) and 192.619(c).

    Answer:

    Section 192.619(a) states that pipeline operating pressure cannot exceed *the lowest of four different criteria*, which are specified in subsections 1-4. The four criteria must be compared, and the one with the lowest result is determinative. The criterion described in § 192.619(a)(3) is a five-year look-back at actual operating pressure, but is only one of the four criteria that must be compared. The criteria in § 192.619(a) include (1) design records and (2) a pressure test. One cannot ascertain which of the four methods in Section 192.619(a)(1)-(4) is lowest without records for all four. Such records are required by Sections 192.603(b) and 192.605(b)(1).

    § 192.619(c) is commonly referred to as the "Grandfather Clause," and states that the pressure restrictions in (a) do not apply to pre-code pipe that is in satisfactory condition, considering its operating and maintenance history. The MAOP for such pipelines is the highest actual operating pressure to which the pipe was subjected during the 5 years prior to July 1, 1970. (See FAQs #15 and #16)

15. Why do operators need records and documentation for all four of (a)(1), (2), (3), and (4)?

    Answer:

    Section 192.619(a) states that pipeline operating pressure cannot exceed MAOP or *the lowest of four different criteria*. The four criteria must be compared, and the one with the lowest result is determinative. One cannot ascertain which of the four methods in Section 192.619(a)(1)-(4) is lowest without records for all four. Such records are required by Sections 192.603(b) and 192.605(b)(1). (See FAQs #14 and #16)

16. Many operators have the view that the Code currently does not require pipeline operators to have complete records in each MAOP category (Section 192.619(a)(1 – 4), (b), and (c)). Many pipeline operators kept MAOP records for only the method they used to establish MAOP. Why should they need additional records?

Answer:

49 CFR § 192.619 requirements in August 1970 were similar to the present Code sections. Neither 1970 nor today's version of Section 192.619(a) allows an operator to operate a pipeline segment at a pressure that exceeds the lowest of the following: design pressure; pressure test divided by a factor in table; highest actual operating pressure for the 5-years prior to July 1, 1970; and maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

Section 192.603(b) requires operators to "keep records necessary to administer the procedures established under § 192.605." Section 192.605(b)(1) requires operators to address "(1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart M of this part." Part 192.619 is one of the requirements subpart L. Therefore, pipeline operators are required to have records for each element in Section 192.619. (See FAQs #14 and #15)

17. Some States may have different pressure test requirements from Federal Code, 49 CFR Part 192 for the intrastate pipelines they regulate. How will these differences be addressed for gas transmission pipelines?

    Answer:

    Any State pipeline safety criteria must meet the minimum 49 CFR Part 192 requirements for gas pipelines, must be compatible if they exceed the federal requirements, and should be accounted for in an operator's IVP program for pipe segments in applicable states.

18. What if a State has accepted pressure tests for less than 8-hours such as 1-hour tests? Are these shorter pressure tests acceptable?

    Answer:

    Such tests would not meet the minimum requirements of Part 192, Subpart J, which requires a minimum 8-hour pressure test hold time.

19. How will the statutory requirements relating to consideration of minimization of costs and service disruptions be addressed?

Answer:

PHMSA will fully analyze the costs and benefits as part of any rulemaking proceeding and will also consult with the Federal Energy Regulatory Commission (FERC) on any issues related to cost/service disruptions.

20. Do you believe that in-service pressure testing, lowering pressure, ILI or replacement of thousands of miles in Class 3 and 4 areas and Class 1 and 2 HCAs can be managed from Washington DC or should LDC (intrastate) operators submit plans to their state commissions for review as is done in California? Should the review process include PHMSA oversight?

    Answer:

    The interstate and intrastate pipeline systems will be inspected by the States and PHMSA on the same basis as they are normally inspected. Pipeline operators would submit plans based upon the requirements for submittals to State or Federal regulators in the IVP regulation.

21. Does IVP apply to mainline pipe or all pipeline appurtenances, such as valves, fittings, metering stations, compressor stations, header manifolds, laterals, or stubs?

    Answer:

    PHMSA's preliminary approach is that IVP will apply to mainline pipe segments that cannot be isolated from the mainline by a valve. Under this approach, a pipeline less than 2-inches or with strength less than API Grade X42 would not be included. It should not include meter stations, compressor stations, header manifolds, or stubs. Treatment of laterals would be based upon diameter, grade, MAOP and length.

22. Will IVP impact pipelines operating at 80% SMYS under the "alternative MAOP" regulations?

    Answer:

    Pipelines with MAOP established in accordance with Section 192.619(d) (80% SMYS or "alternative MAOP") would not be exempt from the IVP requirements. Such alternative MAOP pipelines must comply with applicable Code requirements, and

keep records to document the basis for the MAOP. However, pipelines that qualified to have their MAOP established under Section 192.619(d) should not have record deficiencies that would meet the proposed screening criteria to require application of the integrity verification process.

23. Will IVP impact pipelines operating above 72% SMYS in accordance with the Grandfather Clause, Section 192.619(c)?

    Answer:

    If located in an HCA or MCA, IVP would impact pipelines operating above 72% SMYS similarly to how it will affect other pipeline segments with the same threats. PHMSA has not yet developed any specific criteria for grandfathered, Section 192.619(c), pipeline segments. Grandfathered pipeline segments that operate above 72% SMYS may need to have different criteria in areas that pose a greater threat to the public.

24. Will IVP impact special permit pipelines operating above 72% SMYS, where the class location has changed from Class 1 to 2 or3?

    Answer:

    If located in an HCA or MCA, IVP would impact pipelines operating above 72% SMYS similarly to how it will affect other pipeline segments with the same threats. PHMSA has strong integrity criteria in the class location special permits it has issued in recent years. If a particular class location special permit issued many years ago does not have strong integrity criteria, it would probably need to be updated in accordance with IVP.

25. If MCA is for 1-building or for 1-person in an occupied site, it will mean shutting down a pipeline system to conduct pressure test. This could have a very large impact on deliveries.

    Answer:

    MCAs can be evaluated by means other than pressure testing. PHMSA would expect pipeline operators to use a combination of pressure tests, ILI, ECA, and some other technology for evaluations.

26. Will IVP affect Class 1 pipelines that are not in an MCA?

Answer:

Under PHMSA's current approach to IVP, the answer is no. IVP is not intended for Class 1 pipe segments outside of HCAs or MCAs, because these are pipe segments that should not significantly affect people or the environment should they have a leak or other failure. Operators must still comply with current Code requirements for Class 1 segments outside of HCAs and MCAs. Operators should have procedures in place to meet current requirements to document pipe attributes including MAOP.

27. Is the IVP flowchart to be used to establish MAOP in absence of records verification?

Answer:

The IVP flowchart is meant to illustrate the screening criteria for pipe segments that would require records verification. Pipeline operators that do not have pipe records for segments located in HCAs or MCAs should follow Part 192 in sampling pipe for diameter, wall thickness, grade, and seam type. Part 192 has requirements for pressure test documentation in Subpart J, § 192.517.

28. Does PHMSA want to apply the IVP flowchart to broader Integrity Management issues?

Answer:

PHMSA is considering applying the IVP process to MCAs and HCAs, but it is not intended to be a substitute or proxy for Integrity Management (IM) programs. PHMSA would expect operators to coordinate their IVP process with IM processes to achieve gains in efficiency with respect to meeting both IM and IVP requirements (e.g., selecting integrity assessment methods that achieve with both IVP and IM objectives). Some pipe segments of the IVP may require reassessments similar to what is required for IM.

29. What is "Legacy Problematic Pipe Manufacturing" in Step 11?

Answer:

"Legacy problematic pipe manufacturing" is pipe with manufacturing issues such as LF-ERW or electric flash welded (EFW) pipe or pipe with seam design factors less than 1.0, regardless of date of manufacture.

30. Why does IVP address low stress pipe less than 20% stress?

Answer:

PHMSA has been charged by both Congressional mandate and NTSB recommendations to develop guidelines for all gas transmission pipelines including low stress pipe. Pipeline ruptures have occurred in pipe operating at less than 20% SMYS. PHMSA will consider whether the IVP process should or should not include pipe operating at less than 20% SMYS.

31. Does the IVP criterion associated with operating stress levels apply to segments that currently operate at pressures greater than or equal to 20% SMYS or to segments that have an MAOP of greater than or equal to 20% SMYS?

Answer:

The operating stress level criterion applies to an MAOP of 20% SMYS or more. The definition of gas transmission line can be found in § 192.3.

32. What is the definition of "Validated Traceable Material Documentation"? What is a traceable, verifiable and complete record?

Answer:

Validated Traceable Material Documentation would include records such as a pipe mill test record for mechanical and chemical properties or hydrostatic test records that document the type of test, results of the test, date of the test, and person or organization who conducted the test. Each record would be signed or initialed by the organization designated person.

When analyzing whether records are traceable, verifiable and complete, an operator should consider the entire set of records supporting the MAOP and whether the documentation, as a whole, is traceable, verifiable and complete, as these three characteristics of the record are interrelated.

33. How are pipeline systems expected to operate during material documentation and pressure test time intervals?

    Answer:

    PHMSA's current approach envisions the implementation of IVP requirements to extend over a time period similar to or greater than the integrity management regulations, with more critical areas to be scheduled in earlier time periods. PHMSA proposes to allow pipelines to operate as they have in the past during the implementation phase of IVP.

34. Do you believe government, service providers and industry should work collaboratively to establish performance criteria for using ILI in lieu of pressure tests? The criteria could include pipe grade, wall thickness, defect size, and other information needed to predict that pipe would conservatively fail a 1.25 times MAOP pressure test.

    Answer:

    Yes, PHMSA believes all affected stakeholders including the public should have input into establishing performance criteria. The workshop, federal docket, and the formal rulemaking will allow the public, service providers, industry and both state and federal government to provide their input.

35. What are the goals of the IVP methodology using Steps 9, 13, 14, and 15 (which appears to be randomly cutting out pipe coupons) for at least 93,000 miles of gas transmission pipe as the primary method to ensure the proper MAOP is established?

    Answer:

    The goal of the IVP methodology being developed is to establish the integrity of the pipe segment and ensure threats such as cracking or seam concerns can be evaluated with all relevant information about material attributes such as wall thickness, grade and seam type. The IVP Workshop was held to invite feedback and ideas on how to properly implement the Congressional mandates and NTSB recommendations.

    Pipeline operators should review their pipe and other material documentation procedures on new construction and maintenance to ensure they are properly

documenting the material being used in their pipeline segments to establish/maintain MAOP and to maintain integrity when evaluating threats to the pipeline.

36. Why is there no difference in Steps 2-5 (which address Section 192.619(a)) for pre-regulation and post-regulation lines?

    Answer:

    Those screening criteria (IVP Chart Steps 2-5) would apply to any pipe segment whose MAOP was established in accordance with Section 192.619(a), regardless of the date of manufacture or system completion/startup.

37. Will PHMSA be providing additional guidance with respect to the amount of deration (Step 17 – Derate Pipeline Commensurate to Class Location…)?

    Answer:

    Yes. Operators can expect any NPRM issued on this subject to address this topic.

38. Will PHMSA be providing additional guidance with respect to Remaining Life Analysis (Step 17– Derate Pipeline Commensurate to Class Location…)?

    Answer:

    Yes. An NPRM would have information on this topic.

39. If operators have already taken significant actions in good faith, for example they have already pressure tested segments, would IVP invalidate those efforts if they were not in strict conformance with the IVP requirements?

    Answer:

    Operators would be required to comply with any pipeline regulations that might be promulgated. In general, PHMSA does not know if actions already taken by an operator will satisfy the requirements of IVP regulations. For example, if a Class 1 segment manufactured with legacy techniques such as LF-ERW was only tested to less than 1.1 times MAOP; such test would not comply with the proposed IVP process for legacy pipe. Under the proposed IVP process, such segments would need to be tested to at least 1.25 times MAOP, with a spike test.

40. If an operator has records that are useful but not fully adequate, would PHMSA consider allowing a pressure test to validate material strength without providing material documentation?

    Answer:

    Depending on the specific situation, it is possible that, in some cases, a pressure test alone might suffice. However, confirmation of pressure carrying capacity of the pipe does not provide all information necessary for ongoing operating and maintenance requirements. For example, in order to determine the predicted failure pressure of a metal loss anomaly, the operator must know the pipe strength and wall thickness. Without this information, engineering analysis evaluation methods such as ASME B31G or RSTRENG cannot be used to determine if metal loss defects must be repaired. Refer to section 4.2 of ASME B31.8S. However, if the pressure test is properly conducted and documented, it can provide useful information with which operators could make conservative assumptions regarding material strength.

41. Will operators be able to continue to set operating pressure based on the 5-year pre-Code maximum operating pressure without a pressure test?

    Answer:

    Under PHMSA's current proposed approach, the grandfather clause would continue to remain in effect for pipe located outside of any HCA or MCA, or that otherwise do not meet the screening criteria for application of the integrity verification process.

42. Please clarify if Sections 192.619(a)(3) and (a)(4) apply to pre-code pipe, post-code pipe, or both.

    Answer:

    Sections 192.619(a)(3) and (a)(4) do not apply to pipeline segments that became operational after July 1, 1970. However, those requirements do apply to pipeline segments that were operational as of July 1, 1970, and whose MAOP was established under Section 192.619(a), instead of the Grandfather Clause Section 192.619(c).

43. Are IVP required pressure tests for one time only?

If the pipe segment MAOP is established and records are kept, then no other pressure tests or ILI requirements should be required unless defects such as seam or pipe material issues are found. The IVP regulations might require future retests or ILI evaluations depending on threats, material attributes, and operational pressure fluctuations.

44. Will a 1.25 times MAOP pressure test be acceptable for material and construction defects including cracks and corrosion?

    Answer:

    Under the approach currently being considered by PHMSA, modern pipe and pre-1970 pipe that does not have legacy or integrity issues such as seam cracking issues, a 1.25 times MAOP test should be acceptable. Note, however, that a pressure test that would also be used to establish or confirm MAOP must meet the test pressure requirements in Section 192.619(a) for the class location in which the pipe is located. Pipes with seams such as low frequency electric resistance weld (LF-ERW), Youngstown Steel, would probably require a "spike test" at a higher pressure in addition to a Subpart J test at 1.25 times MAOP, as recommended by National Transportation Safety Board (NTSB) NTSB- P-11-14.

45. Should a "spike pressure test" be commensurate with segment specific issues?

    Answer:

    Yes, usage of a "spike pressure test" would be used based upon the segment specific threats. A spike test would be mostly used for cracking type threats such as seam defects or stress corrosion cracking issues.

46. What are the specific requirements for a "spike pressure test"?

    Answer:

    Criteria for a "spike pressure test" have not yet been developed. A spike test is normally in the 100% to 110% of specified minimum yield strength (SMYS) range and is held for a length of 15 minutes to 1-hour as part of a 49 CFR Part 192, Subpart J, 8-hour pressure test.

47. Will IVP require applying a “spike pressure test” required by NTSB on all threats or just seam corrosion?

    Answer:

    Criteria for a “spike pressure test” have not yet been developed. Among other things, PHMSA will consider NTSB’s findings and recommendations in developing pressure test, in-line inspection (ILI), and engineering critical assessment (ECA) criteria.

48. Why recommend spike tests, if the San Bruno spike in pressure caused the rupture?

    Answer:

    The San Bruno maintenance-caused operational spike was at or just below MAOP of the line. A spike pressure test, with line purged of natural gas and filled with water, is important to confirm material adequacy, by causing weak or damaged places in the pipe to rupture or leak and be repaired to assure that the pipe is capable of safely operating at MAOP with safety margin.

49. Will there be different records/material verification requirements for fittings and components?

    Answer:

    The proposed IVP approach would require that fittings and components meet the specifications and ratings (such as American National Standards Institute (ANSI) or Manufacturers Standardization Society (MSS)) in effect when they were manufactured. Evidence of such could be verified through field observation of code stamps or other discernible markings or features. The material specification or standard may need to be verified in some cases.

50. What lengths of pipe will be required to be sampled, cut out and tested, to establish material properties and what is the technical justification?

    Answer:

    PHMSA has not yet developed generally applicable requirements on how much in-service pipe would need to be cut-out. Pipeline operators would need to develop procedures to sample pipe segments that do not have material documentation based upon the integrity needs and shortcomings in the documentation for the segment

specific to their pipelines. PHMSA expects the material documentation process procedures to include *in situ* non-destructive tests, tests of materials from cut-outs for segment removals such as relocations, and conservative procedures for threat assessments for safe pressures.

51. Why cut out and test pipe samples to establish material properties, if pipe has been pressure tested or pressure de-rated?

    Answer:

    Pipeline operators must have documents that confirm the strength (SMYS), wall thickness, and seam type of the pipe for MAOP determination, operations, and IM (See FAQ #16 and #40). This information is needed for IM risk analysis, determination of failure pressure ratios (FRP) or safe pressures of defects, etc. In many cases, a pipeline operator would not be required to cut-out pipe samples from an in-service pipeline. A documentation plan may include cut-outs of in-service or material property tests when segments are removed (such as for relocations or anomaly cut-outs). Where pipe properties are not documented, an operator may need to use more conservative defect repair criteria that include *in-situ* nondestructive examination (NDE) testing and chemistry checks. More conservative repair criteria might also be called for when using R-STRENG or other technical analysis methods. These *in-situ* methods would need to be reviewed by PHMSA or criteria added to the regulations.

52. Will PHMSA provide guidance for cutouts?

    Answer:

    Yes, the NPRM will provide proposed regulations for public input.

53. If an operator does not have material records for fittings, is it acceptable to assume that fittings are Grade B?

    Answer:

    No. Current DOT Part 192 Code allows Grade A fittings. A conservative assumption could be to assume Grade A fittings. The IVP regulations will have guidance on material documentation.

54. Will there be provisions to allow for in-the-ditch methodologies to establish material or pipe properties in lieu of cut-outs?

Answer:

The proposed IVP process would allow for the use of in-the-ditch methodologies to establish material properties such as strength and chemical properties. Such methodologies would need to be demonstrated to be valid for the vintage/grade of pipe being tested.

55. To address data gaps for fittings and components, would PHMSA find it acceptable to rely on construction industry standards in effect at the time of manufacture and installation?

Answer:

Yes, if an operator confirms that fittings and components complied with codes and specifications in effect at the time of manufacture and installation but operator's would need to make these component manufacturer specifications part of their permanent documentation.

56. The IVP process includes confirming or determining material properties and documentation prior to deciding which assessment to make. If an operator pressure tests the segment, is it still necessary to perform material documentation actions?

Answer:

Although operators do not have to wait for the completion of material documentation to perform its pressure test or other assessments to establish MAOP, in many cases it is still necessary to confirm or determine material properties and documentation. See response to FAQs #40 and #51 for examples of why material documentation is still needed.