Frequently Asked Questions (FAQs) on Gas Transmission Final Rule

Title: Frequently Asked Questions (FAQ) for the Final Rule titled "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," published on October 1, 2019

Date: September 15, 2020

Summary:

PHMSA is issuing these Frequently Asked Questions (FAQs) to assist gas pipeline owners and operators in complying with the pipeline safety regulations in 49 CFR Parts 191 and 192. These regulations were amended on October 1, 2019, by the Final Rule entitled "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments" (84 FR 52180). This guidance document was not deemed "significant" or "otherwise of importance to the Department's interests," as defined by 49 CFR 5.37. However, PHMSA voluntarily posted the FAQs to the Federal Register on January 29, 2020, for public comment, under Docket Number PHMSA-2019-0225. A public meeting was then held on February 27, 2020. In finalizing this guidance document, PHMSA considered comments made at the public meeting along with the 18 comments submitted to the docket as of March 30, 2020. This guidance document is not intended to replace or revise any previously issued guidance.

This guidance does not have the force and effect of law and is not meant to bind the public in any way, although pipeline operators must still comply with the underlying safety standards. These FAQs are only intended to clarify existing requirements under the pipeline safety laws, PHMSA regulations, and agency policies.

General FAQs

FAQ-1. What are key implementation dates associated with this Final Rule?

July 1, 2020

- Operators must prepare and follow procedures (per §§ 192.13(c) and 192.605) addressing applicable regulations without timeframes explicitly defined in the Final Rule (§§ 191.23, 191.25, 192.3, 192.5, 192.7, 192.9, 192.18, 192.67, 192.127, 192.150, 192.205, 192.493, 192.506, 192.517, 192.607 (if material verification is being used per § 192.712), 192.619, 192.632, 192.710, 192.712, 192.805, 192.909, 192.917, 192.921, 192.933, 192.935, 192.937, 192.939, 192.949 (removed and replaced with 192.18), and Appendix F to Part 192.
- Operators must begin to identify, schedule (according to a risk-based prioritization), and perform assessments required by § 192.710 (see FAQ-12 regarding MCA identification).

July 1, 2021

- Operators must begin retaining records for each individual welder qualification at the time of construction for a minimum of 5 years following construction, per § 192.227.
- For transmission pipe installed after July 1, 2021, operators must begin retaining records for each person's plastic pipe joining qualifications at the time of construction for a minimum of 5 years following construction, per § 192.285.
- If subject to § 192.624, operators must develop and document procedures for completing all actions required by this section (see FAQ-12 regarding MCA identification). These procedures must include:
  - A process for reconfirming MAOP for any pipelines that meet a condition of § 192.624(a)
  - A process for performing a spike test or material verification per §§ 192.506 and 192.607, if applicable
  - A process for performing an engineering critical assessment (ECA) for MAOP reconfirmation per § 192.632, if implemented
- Operators must modify their launchers and receivers that will be used after this date to meet the conditions of §192.750.

March 15, 2022

- Operators must submit a revised Annual Report (PHMSA F 7100.2-1) that reflect this rulemaking.

July 3, 2028

- Operators must complete all actions required by § 192.624 on at least 50% of the pipeline mileage subject to MAOP reconfirmation.

July 3, 2034

- Operators must complete all originally identified assessments required by § 192.710.

July 2, 2035

- Operators must complete all actions required by § 192.624 on 100% of the pipeline mileage subject to MAOP reconfirmation.

FAQ-2. Do any of the new rules apply to regulated gas gathering lines?

Yes. While the new rule focuses on the safety of onshore gas transmission lines, new requirements apply to regulated gas gathering lines. Section § 192.9 identifies the safety requirements applicable to regulated gas gathering lines. Sections §§ 192.9(b), 192.9(c), and 192.9(d) identify code sections that do not apply to gas gathering lines. Operators of regulated gas gathering lines should review the following code sections, revised in this rulemaking, to see how they apply to their systems: §§ 191.23, 191.25, 192.3, 192.5, 192.7, 192.18, 192.67, 192.127, 192.205, 192.227, 192.517, 192.619(a), 192.619(f), 192.750, and 192.805.

FAQ-3. Who qualifies as a "subject matter expert" for purposes of reviewing and validating failure pressure analyses under § 192.712?

PHMSA described the qualifications of a "subject matter expert" in the Preamble of the Final Rule at 84 FR 52206: *PHMSA expects a qualified subject matter expert to be an individual with formal or on-the-job technical training in the technical or operational area being analyzed, evaluated, or assessed. The operator must be able to document that the individual is appropriately knowledgeable and experienced in the subject being assessed.*

The intent of § 192.712 is to require operators to conduct rigorous failure pressure analyses that are properly documented, for review and evaluation by qualified experts. Subject matter experts don't necessarily need to perform the analyses, but they must review and confirm the analyses.

FAQ-4. **What date or what activities should an operator use to compute the beginning of the five-year period from which it needs to retain individual joining or welding qualification records pursuant to § 192.227(c)?**

Records required by 192.227(c) must be retained for a minimum of five years after the end of construction. PHMSA considers the end of construction to be prior to an operator placing a gas, as defined by §§ 192.1(a) and 192.3, into the pipeline, making it an in-service pipeline, and operating that pipeline. Per § 192.227(c), "construction" activities include the installation of pipe—be it for new construction, replacement, relocation, or repair. These construction activities would also include the installation or replacement of components with pipe attached.

FAQ-5. Removed.

Reporting FAQs

FAQ-6. When is the effective date of the revised incident report form? (The revised form requires collecting data on the MAOP reconfirmation method and moderate consequence area location for the pipe segment involved in an incident.)

Operators can report new data requirements on the revised incident form (Form PHMSA F 7100.2) starting July 1, 2021. However, operators can view this revised form currently on the docket (PHMSA-2019-0225). Section 191.15 requires each operator of a transmission or a gathering pipeline system to submit DOT Form PHMSA F 7100.2 as soon as practicable, but not more than 30 days after detecting an incident required to be reported under § 191.5 of Part 191. The form has been modified to collect information and data the pipeline operator must obtain as part of the Final Rule, including a record(s) of the maximum allowable operating pressure (MAOP) reconfirmation method used for the pipeline segment that experienced the incident, and whether the incident occurred in a moderate consequence area (MCA). Operators must identify MCAs to determine if the new requirements under §§ 192.624(a) and 192.710(a) apply to them.

FAQ-7. When will Form PHMSA F 7100.2-1 (annual report) be revised to reflect the additional information that PHMSA expects to collect for miles of pipe in MCAs and MAOP reconfirmation?

The revised annual report form (Form PHMSA F 7100.2-1) for gas transmission pipelines has been modified to collect MCA and MAOP reconfirmation information. Operators will be able to start using the annual report form on July 1, 2021. Operators, however, can view this revised form currently on the docket (PHMSA-2019-0225). PHMSA will require operators to use the revised annual report form beginning Calendar Year 2021, due no later than March 15, 2022. The Final Rule does not require modifications of the annual report for gas distribution; therefore, that report remains unchanged.

Other Technology Notification FAQs

FAQ-8. Does the notification process set forth in § 192.18 apply to all of Part 192?

No. The notification guidance in § 192.18(a) and (b) applies to all sections of Part 192. The sections specifically identified in § 192.18(c) require that the operator provide notification to PHMSA at least 90 days prior to using other technologies or methodologies. These sections include as follows: §§ 192.506(b), 192.607(e)(4), 192.607(e)(5), 192.624(c)(2)(iii), 192.624(c)(6), 192.632(b)(3), 192.710(c)(7), 192.712(d)(3)(iv), 192.712(e)(2)(i)(E), 192.921(a)(7), or 192.937(c)(7). Operators are also required to notify PHMSA of changes to their Operator Qualification and Integrity Management plans per § 192.805(i) and § 192.909 (b), respectively.

FAQ-9. Removed.

FAQ-10. Must operators wait for written approval from PHMSA prior to implementing other technology for purposes of complying with the sections identified in § 192.18(c)?

No, operators may proceed with using other technologies <u>if</u> they submitted a notification per § 192.18 <u>and</u> PHMSA did not respond within 90 days. After 90 days following notification submission, an operator does not have to wait for a written approval or a “no objection letter” from PHMSA to proceed with using “other technology.” An operator seeking a written “no objection letter” from PHMSA prior to implementing the alternative technology per § 192.18(c) should include a specific request for the written response in its § 192.18 notification.

Moderate Consequence Area (MCA) FAQs

FAQ-11. In identifying MCAs affecting their pipelines, where can operators obtain information as to the location of a designated interstate, other freeway or expressway, and other principal arterial roadway with 4 or more lanes?

To identify applicable roadways, PHMSA expects operators to use all information available including but not limited to the following: www.thenationalmap.gov, www.fhwa.dot.gov, and other federal and state highway mapping data; aerial imagery; pipeline patrols and surveys (ground and aerial); and, pipeline route maps. When identifying an MCA, PHMSA expects operators to capture the area between the outermost edge of the paved surfaces, including all medians. Entrance and exit ramps to access-controlled roadways should be included in the MCA analysis. There is no comprehensive GIS-based source of roadways as defined in the Federal Highway Administration's (FHWA) *Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1* (see: https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/fcauab.pdf). However, Section 4 of the FHWA document includes recommendations and guidance on how to obtain GIS-based roadway inventory data at a state level. PHMSA does not intend to develop a single source of data for operators to use to determine if an MCA exists on their pipeline system.

FAQ-12. When must operators complete the initial determination of MCAs on their pipeline system?

The new rule, which went into effect July 1, 2020, requires operators to develop procedures per § 192.605(b)(1) to determine the location of MCAs on their pipeline system and to incorporate these procedures into their manual for maintenance and normal operations. Operators must then implement those procedures to complete the initial identification of MCAs by July 1, 2021 and record those MCAs in the revised incident and annual reports after this date. (See FAQ-6 and FAQ-7.)

PHMSA anticipates that some operators will incorporate an MCA identification process into existing HCA and class identification procedures, while other operators might prepare a separate procedure for identifying MCAs. MCAs are used to determine a pipeline segment's applicability under §§ 192.624 and 192.710.

Operators must begin performing assessments according to a risk-based prioritization schedule starting July 1, 2020, the effective date of the rule, and complete all assessments no later than July 3, 2034, per § 192.710(b). Operators must also begin performing MAOP reconfirmations on July 1, 2021, to complete all actions required by the schedules in § 192.624(b)(1) and (2).

An assessment performed prior to July 1, 2020, the effective date of the rule, that meets the conditions outlined in § 192.710(b)(3) may be used as an assessment. Operators who use a prior assessment for a pipeline segment located in an MCA must conduct ongoing reassessments of that segment within 10 years as per § 192.710(b)(2)—not 14 years as would be the case for an initial assessment under § 192.710(b)(1).

FAQ-13. Do operators need to identify, document, and track "unpiggable" MCAs operating less than 30% Specified Minimum Yield Strength (SMYS)?

Yes. Operators must identify, document and track all MCAs—regardless of piggability and operating stress—for annual and incident report data collection.

FAQ-14. How frequently must a re-evaluation of MCAs be performed and when must new MCAs be incorporated into an operator's plans and procedures?

PHMSA expects that operators will re-evaluate their MCAs once per calendar year, not to exceed a period of 15 months, consistent with current HCA and class location change studies (per §§ 192.905 and 192.609). PHMSA also expects that operators will add any newly identified MCAs to their § 192.710 assessment schedule within one year of the discovery date. This expectation is consistent with current Gas IMP FAQ-19, FAQ-20, and FAQ-179, posted on the PHMSA's Technical Resources site at https://www.phmsa.dot.gov/pipeline/gas-transmission-integrity-management/gas-transmission-integrity-management-faqs.

Spike Hydrostatic Testing FAQs

FAQ-15. Under § 192.506 *Transmission lines: Spike hydrostatic pressure test*, is a spike test required for all pipelines that are hydrotested (or re-hydrotested) and are operating at 30% or more of SMYS? For what threats is a spike hydrostatic pressure test appropriate?

No. A spike test is not required for all pipelines that are hydrotested or re-hydrotested and are operating at 30% or more of SMYS. The hydrostatic spike pressure testing requirements in § 192.506 applies only when conducted as required by §§ 192.710 and 192.921.

A spike test is appropriate and should be considered for time-dependent threats, such as the following: stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and, other forms of defect or damage involving cracks or crack-like defects, such as those listed in §§ 192.710(c)(3), 192.917(e)(6) and 192.937(c)(3).

If an operator decides to spike test a transmission pipeline operated at a hoop stress greater than 30% SMYS, the test must be conducted according to the spike-test procedures listed in § 192.506.

Material Verification FAQs

FAQ-16. Is the use of § 192.607 Verification of Pipeline Material Properties and Attributes allowed outside of HCAs, MCAs, and Class 3 and Class 4 locations?

Yes. While pipeline operators must verify material properties per § 192.607 where explicitly referenced in Part 192, PHMSA also allows the voluntary use of § 192.607 (per § 192.619(a)(4)) for material property verification outside of HCAs, MCAs, and Class 3 and Class 4 locations in order to determine key Subpart C – Pipe Design attributes. Operators of pipeline segments that do not meet the applicability of § 192.624 may, and in fact are encouraged to, conduct and use the results of a properly conducted testing program such as those outlined in §192.607 to ensure the safe operation of the pipeline regardless of location. That said, operators must consider the newly determined material property results regardless of pipeline location when they analyze predicted failure pressures for anomalies, develop appropriate repair procedures, conduct engineering critical assessments, or fulfill other requirements under Part 192.

FAQ-17. PHMSA allows the data collection process to be accomplished "opportunistically" per § 192.607(c). Is there a deadline by which operators are expected to complete this process?

No. The opportunistic gathering of data on unknown material properties does not need to meet the MAOP reconfirmation schedule outlined in § 192.624(b), except when the selected MAOP reconfirmation method requires material properties testing to reconfirm the MAOP. The timeframe for opportunistic data collection may vary, based on the length of the pipeline, amount of pipe with missing material properties, number of opportunities, and testing results. (See § 192.607 for a complete description.) Also, § 192.712 requires the operator to know the pipe material properties when conducting the analysis of predicted failure pressure for anomalies or defect evaluations.

FAQ-18. When determining separate pipe "populations" for conducting a verifiable material properties and attributes sampling program that satisfies § 192.607(e)(1), must an operator compare the dates of manufacture and construction together, or must the manufacture and construction dates be compared separately? For example, would two segments of pipe that were manufactured in the same year but were installed together, 3 years after manufacture, be in the same population? As a second example, would two segments of pipe that were manufactured in the same year but installed 3 years apart be in the same population?

When determining the vintage of two potentially similar pipeline segments (e.g., same diameter, wall thickness, grade, and seam type), operators must consider the following: If the difference between either the manufacturing date of the two segments or the construction date of the two segments is greater than 2 years, the two segments cannot be considered similar and must be placed in separate populations per the mandate in § 192.607(e)(1). In the first example, the two pipe segments would be in the same population. In the second example, the operator would not be able to place the two pipe segments in the same population unless additional records demonstrate traceability to another population of pipe.

FAQ-19. It appears to be a requirement to separate pipe segments into different populations based on the material properties and attributes listed in § 192.607(e)(1), but how do you handle the situation where you are missing documentation for an attribute like pipe manufacturing dates?

Operators should only split populations based on known attributes and they should have separate populations of pipe segments where attributes are unknown. Operators that can document pipe material properties but are missing the manufacturing or construction date attributes would not need to conduct an expanded sampling program to determine material properties. When material attributes are unknown, operators must use manufacturing and construction dates noted in § 192.607(e)(1) and FAQ-18 to delineate the boundaries of the material properties sampling program.

FAQ-20. How should operators define populations where necessary documentation is missing? Can an operator group all pipe sections with unknown attributes into one population?

Per § 192.607, operators must implement a sampling program for each unique pipe population group with unknown pipe attributes. Operators can initially group pipe segments with no known material properties information into a single population. When performing material properties testing on pipe from the unknown population group, operators must add newly verified samples into matching pipe populations or create new pipe population groups, as applicable.

FAQ-21. Can the data from in-line inspection tools be used to help determine population groups under § 192.607(e)?

Yes. In-line inspection data may be used to delineate various pipe population groups for subsequent sampling of multiple segments for material property verification. Operators must define processes they plan to implement the requirements of MAOP reconfirmation and material verification, and report whether they are using an alternative sampling approach under § 192.607(e)(5). This alternate sampling method must also be reported per § 192.18.

FAQ-22. Can an operator use SMYS, wall thickness and seam type derived from in-line inspection tools for material verification under § 192.607(c)?

Yes. Depending on the in-line inspection tool capabilities, operators can determine certain material properties and attributes with the required confidence levels. Any verification of material properties and attributes using nondestructive methods or inspection tools must meet the requirements in § 192.607(d).

FAQ-23. Is there a process to compile comparable pipe material properties across the industry?

No process currently exists to compile pipe material property information. Material properties can vary greatly during the manufacturing process. PHMSA expects operators to verify pipe material used within their system.

FAQ-24. During which type of pipeline exposures does an operator need to perform material properties and attributes verification?

Operators must address each activity listed in § 192.607(c) in their procedures for safely conducting nondestructive or destructive tests, examinations, and assessments to verify the material properties. The listed activities include: anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations associated with replacements or relocations of pipeline segments that are removed from service. Operators' procedures should establish specific criteria for identifying when these pipeline exposures are safe "opportunities" for material verification and identify any criteria that would render an exposure inappropriate for material verification, such as confined space concerns or unstable excavations. In most cases, an operator should be able to conduct material properties tests after completing an immediate repair. PHMSA does not expect operators to perform material properties verification for unknown pipe properties on pipeline segments exposed during excavation activities per § 192.614 *Damage Prevention Program.* However, material verification performed during a one-call excavation must be performed per §192.607.

FAQ-25. If an operator has unknown material properties and during normal operations excavates a leak on a transmission line operating at less than 30% SMYS, must it perform a destructive or nondestructive test to verify material properties?

After making the area safe, an operator must perform testing to verify pipeline material properties and attributes per § 192.607 if the pipeline segment experiencing the leak meets applicability per §§ 192.624 *Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines,* or per 192.712 *Analysis of Predicted Failure Pressure*.

FAQ-26. In accordance with § 192.607, what pipe material properties or attributes must be verified through *in situ* (non-destructive) testing during an excavation and exposure of the pipeline?

Operators must verify diameter, wall thickness, seam type, and grade (e.g., yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), and Charpy v-notch toughness values (if needed), if these items are unknown and are necessary for MAOP reconfirmation (per § 192.624), an engineering critical assessment (per § 192.632), or failure pressure analysis (per § 192.712), as specified by those regulations.

Other material properties and attributes might be required to be documented (e.g. Subpart I, Subpart O).

FAQ-27. What are operators expected to do if they find material properties records that do not substantiate MAOP in Class 1 or 2 locations or in non-MCA/HCA segment while complying with § 192.607?

Operators must reduce the operating pressure and MAOP per § 192.619 and may need to perform MAOP Exceedance reporting per §§ 191.23(a)(10) and 191.25(b).

FAQ-28. What does PHMSA mean in § 192.607(e)(4) when it states that an operator must establish an expanded sampling program when it finds line pipe with properties "that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past?"

PHMSA expects operators to define the term "not consistent" in their material verification procedures as it relates to pipe properties, and to detail how they will establish an expanded sampling program in response to such information. The regulation requires operators to maintain material records for line pipe, such as pipe wall thicknesses, grades, and manufacturing process (seam types). Pipeline material records and class location information are used to determine and support the pipeline MAOP. Any operator who discovers pipe properties that differ from those used to determine the pipeline's MAOP should consider such properties to be "not consistent" with available information or assumptions for operations and maintenance. The operator material sampling programs must be modified to comply with the requirements of § 192.607(e)(4).

FAQ-29. Can I collect material information from Class 1 and 2 and non-MCA/non-HCA locations and apply it to segments that require material properties and attributes verification under § 192.607, assuming the pipe is similar? For example, can pipe material properties that are collected and validated for pipe examined outside of HCA, MCA, Class 3 and 4 locations be used if similar pipe is found in an HCA, MCA, Class 3 and 4?

Yes. Operators may take advantage of all pipeline excavations and exposures to collect material properties regardless of pipeline location. If operators plan to use material and attribute information collected from pipe segments outside of HCA, MCA, and Class 3 and 4 areas to fulfill the requirements of §§ 192.624 and 192.712, they must adopt and follow procedures for implementing § 192.607(e) in those areas as well. Any acquired material properties and attribute data will aid the operators' efforts to safely conduct MAOP reconfirmation, pipeline assessments, anomaly evaluations, analysis of failure pressure, and repairs for all pipeline segment irrespective of Class Location or HCA/MCA designation.

If the sampling procedures mandated by § 192.607(e) are used outside of HCA, MCA, or Class 3 or 4 areas, the operator must also include procedures to delineate the geographic limits of the sampled segments and how that pipe material and attribute information will be applied to meet the additional regulatory requirements for HCA, MCA, and Class 3 and 4 areas.

Maximum Allowable Operating Pressure Establishment and Reconfirmation FAQs

FAQ-30. What is meant by "traceable, verifiable, and complete in relation to MAOP records?

The Preamble of the rule at 84 FR 52218, excerpted below, states PHMSA's expectations relative to "TVC" records.

Traceable *records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, which include mechanical and chemical properties; purchase requisition; or as-built documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter. Careful attention should be given to records transcribed from original documents as they may contain errors. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.*

Verifiable *records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a pipeline segment complemented by pressure charts or field logs. Another example might include a purchase order to a pipe mill with pipe specifications verified by a metallurgical test of a coupon pulled from the same pipeline segment. In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by a qualified individual who observed the test or inspection being performed.*

Complete *records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking such as a corporate stamp or seal. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test. A record that cannot be specifically linked to an individual pipeline segment is not a complete record for that segment. Incomplete or partial records are not an adequate basis for establishing MAOP or MOP. If records are unknown or unknowable, a more conservative approach is indicated.*

For example, a mill test report must be traceable, verifiable, and complete, which is a typical record for pipelines. For the mill test report to be traceable it would need to be dated in the same time frame as construction or have some other link relating the mill record to the material installed in the pipeline, such as a work order or project identification. For the mill test report to be verified, it would need to be confirmed by the purchase or project specification for the pipeline or the alignment sheet with consistent information. Such an example would be verified by independent records. For the mill test report to be complete, it must be signed, stamped, or otherwise authenticated as a genuine and true record of the material by the source of the record or information, in this example it could be the pipe mill, supplier, or testing lab.

Another common record is a pressure test record, which must be traceable, verifiable, and complete. For the pressure test record to be traceable, it would need to identify a specific and unique segment of pipe that was tested (such as mileposts, survey stations, etc.) or have some other link relating the pressure test to the physical location of the test segment, such as a work order, project identification, or alignment sheet. For the pressure test record to be verified, it would need to be confirmed by the purchase or project specification for the pipeline or the alignment sheet with consistent information. Such an example would be verified by independent records. For the pressure test record to be complete, it should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, elevation information, and any other information required by § 192.517, as *applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test.*

FAQ-31. What sources of information should operators use to discover segments that require MAOP reconfirmation under § 192.624 (i.e., segments that do not have traceable, verifiable, and complete MAOP records)?

If operators do not have traceable, verifiable and complete records to establish MAOP for segments listed in § 192.624(a), they must reconfirm the segments' MAOP. Therefore, operators should review all existing records, particularly those reflecting pipe replacements, relocations, repairs, or other changes to verify that those modifications have been integrated into their MAOP records. Operators, for example, should compare records of historical repairs, leaks, ruptures, incidents, and in-line inspection data (wall thickness, coating, seam type, joint length, fittings, etc.) against their MAOP records. If the records are incomplete or otherwise inadequate, the operator must reconfirm MAOP for those segments.

FAQ-32. If an operator does not have to reconfirm MAOP under § 192.624, what must it do if it does not have records necessary to establish the MAOP of a pipeline segment? Examples of pipelines that would not be covered under § 192.624 include Class 1 and 2 (non-HCA/non-MCA) onshore transmission lines.

PHMSA requires operators of onshore gas transmission pipelines that do not meet the applicability criteria of § 192.624(a) to comply with the other MAOP and design requirements of Part 192, such as § § 192.603(b), 192.605,192.609, 192.611, 192.619, 192.620, 192.195, 192.201, and 192.739. These code sections all require knowledge of a documented MAOP and the materials of which the pipeline is constructed. Operators who do not have proper records should follow the sections of Part 192 that address pressure testing and/or materials confirmation based on the type of documents that are not available.

FAQ-33. Can an operator take a pressure reduction per § 192.624(c)(2) and not have to reconfirm MAOP?

Yes. An operator performing a pressure reduction based on "Method 2" of § 192.624(c)(2) is reconfirming the pipeline's MAOP by creating a safety margin by which the pipeline is operating. The pressure reduction creates and establishes a new MAOP. The recordkeeping requirements of § 192.619(f) will apply to the MAOP reconfirmation records that document the pressure reduction (i.e., 5-year operating pressures, application of reduction factors, etc.). Note, however, that operators who need traceable, verifiable, and complete records of material properties and attributes to comply with elements of §§ 192.624, 192.632, or 192.712 (for anomaly repairs, an Engineering Critical Assessment, use of another MAOP reconfirmation method, or the calculation of predicted failure pressures, for example) would still need to obtain those records per the opportunistic method described in § 192.607.

FAQ-34. Methods 2 and 5 under § 192.624(c) permit reconfirming MAOP based upon the highest actual operating pressure during the 5 years preceding October 1, 2019. What does "the highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period" mean?

This statement means the 8-hour period does not need to be continuous; it can be made up of shorter periods that over the course of 30-days amount to at least 8 hours above a certain pressure. Per §§ 192.624(c)(2) and (c)(5)(i), the value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (i.e., the location-specific operating pressure at each location) that is protected from over-pressuring (see §§ 192.199 and 192.201).

FAQ-35. After July 1, 2021, if an operator discovers a pipeline segment that meets the applicability criteria under § 192.624 due to a change in class location, when must the operator confirm or revise the MAOP for that segment?

When a change in class location occurs on a pipeline segment, operators must confirm or revise the MAOP for that segment within 24 months from the date the classification changed, per §§ 192.609 and 192.611, not in accordance with MAOP reconfirmation requirements established in § 192.624(b)(2). When an HCA or MCA on a pipeline segment is added or changed, that area will need to comply with § 192.624(a). If this occurs, the operator must reconfirm the MAOP per § 192.624(b)(2). Operators must ensure that the MAOP records for these new segments are traceable, verifiable, and complete.

FAQ-36. If a pipeline is operating at greater than 72% SMYS with a "legacy" MAOP (i.e., established according to § 192.619(c)) and experiences a change in class location from Class 1 to Class 2 or from Class 1 to Class 3, can an operator use § 192.624 to confirm the MAOP?

No. The MAOP of the legacy pipeline segment (+72% SMYS) must still be revised per §§ 192.611(a)(1)(i), 192.611(a)(2), 192.611(a)(3), and 192.619(a), as applicable for the Class location change and the in-service pipeline. To meet these requirements, the operator must use material properties per § 192.105 (or acquire them per § 192.607), and have a hydrotest performed per § 192.619(a)(2). A legacy pipeline with an MAOP above 72% SMYS cannot have a class location change, such as from a Class 1 to a Class 2 location, without either lowering the MAOP to at or below 72% SMYS or replacing the pipe with materials suitable for a Class 2 or Class 3 location design factor and pressure test. However, if the pipeline is operating at a corresponding hoop stress (at or below 72% SMYS) that is commensurate with the present class location, the existing legacy MAOP can be maintained, assuming the legacy MAOP is documented (per §§ 192.603(b) and 192.605(b)(3)) and material properties, pipe design and pipe component records are traceable, verifiable, and complete.

FAQ-37. Is MAOP reconfirmation required for non-line pipe and components within appurtenant facilities, including compressor, meter, and pressure-limiting stations?

Yes. Line pipe and non-line pipe within compressor, meter, and pressure-limiting stations, including bypasses (up to the station emergency shutdown or isolation valves), are subject to § 192.624 and must be incorporated into the operator's MAOP reconfirmation program. PHMSA expects the operator to examine or assess the pressure rating for all above-ground components. For buried components, PHMSA expects operators to implement a sampling program similar to that required for line pipe per § 192.607(e). Under § 192.607(f), testing of components for chemical and mechanical properties is not required.

FAQ-38. Must material property and MAOP reconfirmation records be retained after a pipeline has been abandoned?

No. However, the destruction or loss of such records would prevent the pipeline from operating in the future under Parts 192 or 195 (see conversion of service requirements under §§ 192.14 and 195.5).

FAQ-39. Must water be used for pressure tests to address manufacturing and construction defects?

It depends on the circumstances:

For Non-HCAs Pipeline Segments: Operators must follow § 192.503 general requirements, including test medium, when conducting future pressure tests in non-HCA segments. If the non-HCA segment requires a spike hydrostatic pressure test the threat, the operator must follow 192.710(c)(3) and 192.506.

For HCAs Pipeline segments subject to Subpart O: Operators must follow § 192.917(e)(3) requirements to address manufacturing and construction defects. After July 1, 2020, operators must conduct a hydrostatic pressure test to at least 1.25 of the MAOP to comply with § 192.917(e)(3).

If prior pressure tests (before July 1, 2020) utilized a medium other than water to address manufacturing or construction threats, the operator may continue to rely on those prior tests to demonstrate stability of manufacturing or construction defects under § 192.917(e)(3) if none of the specified events listed in 192.917(e)(3)(i through iii) have occurred. If these events have occurred after the prior pressure test, the HCA pipeline segment must be re-pressure tested using water.

Failure Mechanics FAQs

FAQ-40. What failure or fracture mechanics models can be used to analyze predicted failure pressure under § 192.712?

Failure or fracture mechanics models that may be used are listed in the Preamble of this final rule at 84 FR 52236. All failure models used for the engineering critical assessment (ECA) analysis must be used within each model's technical parameters for the defect type and the pipe or weld material properties. An operator that wants to use a method which is not listed must use a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI).

Examples of technically proven models for calculating predicted failure pressures include the following:

- For the brittle failure mode, the Newman-Raju Model[1] and PipeAssess PI™ software;[2] and
- For the ductile failure mode, Modified Log-Secant Model,[3] API RP 579-1[4] – Level II or Level III, CorLas™ software,[5] PAFFC Model,[6] and PipeAssess PI™ software.

Following an ECA using an appropriate fracture mechanics model, an operator must remediate crack-like anomalies per §§ 192.632, 192.712(d) through (g), and 192.713.

FAQ-41. If Charpy v-notch assumptions are used as provided in §§ 192.712 (e)(2)(i)(C) and (D), does Charpy v-notch testing need to be performed to verify material properties?

Yes. An operator must obtain Charpy v-notch values if these are needed and are unknown. Section 192.712(e)(2) provides that "the analyses performed in accordance with this section must utilize pipe and material properties that are documented in traceable, verifiable, and complete records." If documented data required for any analysis is not available, an operator must obtain

[1] Newman, J.C., and Raju; "Stress Intensity Factors for Cracks in Three Dimensional Finite Bodies Subjected to Tension and Bending Loads;" *Computational Methods in the Mechanics of Fracture*; Elsevier; 1986; pp. 311-334.

[2] Interim Report for Phase II – Task 5 of the Comprehensive Study to Understand Longitudinal ERW Seam Failures, "Summary Report for an Integrity Management Software Tool," May 2017. https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=11469.

[3] ASTM International, ASTM STP 536, "Failure Stress Levels of Flaws in Pressurized Cylinders," 1973.

[4] American Petroleum Institute and American Society of Mechanical Engineers, API 579-1/ASME FFS-1, "Fitness-For-Service," Second Edition, June 2007.

[5] NACE International, NACE Corrosion 96 Paper 255, "Effect of Stress Corrosion Cracking on Integrity and Remaining Life of Natural Gas Pipelines," March 1996.

[6] Pipeline Research Council International, Inc., Topical Report NG-18 No. 193, "Development and Validation of a Ductile Flaw Growth Analysis for Gas Transmission Line Pipe," June 1991.

the undocumented data through § 192.607. Until documented material properties are available, the operator must use conservative assumptions as defined in §§ 192.712(d) and (e).

Assessments Outside of High Consequence Areas FAQs

FAQ-42. What are the response timeframes for anomalies discovered in MCAs?

Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service per § 192.703(b) and (c). Operators must take remedial measures for anomalies in MCAs per § 192.710(f), which in turn reference the applicable remediation sections of §§ 192.485, 192.711, and 192.713. Response timeframes for MCAs will be included in "Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments (PHMSA-2011-0023) Final Rule."

FAQ-43. Are the assessments required by § 192.710(b)(2) to be performed once every 10 calendar years with intervals not to exceed 126 months, or once every ten years (120 months) with intervals not to exceed 126 months?

Section § 192.710(b)(2) states that periodic assessments must be performed "at least once every 10 years, with intervals not to exceed 126 months." PHMSA intends the maximum reassessment interval by an allowable reassessment method to be 10 calendar years. This is consistent with the Subpart O reassessment interval per § 192.939.

FAQ-44. What is the required reassessment interval for a pipeline segment containing both HCAs and MCAs?

A pipeline segment containing HCAs must be reassessed at least once every seven calendar years per § 192.939. If that same pipeline segment also contains MCAs, those areas must be reassessed at least once every 10 calendar years per § 192.710(b)(2). (See FAQ-43.) If operators elect to reduce the reassessment interval for the MCAs to coincide with the shorter reassessment interval required by adjacent HCAs in that same pipeline segment, PHMSA expects their plans, procedures and records to reflect that decision. If an ILI assessment is used for a pipeline which contains both MCAs and HCAs, then the schedule for evaluation of an MCA coincides with the HCA assessment interval (7 years).

Consideration of Public Comments on Batch- 1 Frequently Asked Questions (FAQs) on Gas Transmission Final Rule

Docket Number PHMSA-2019-0225

Title: "Consideration of Public Comments on Frequently Asked Questions (FAQs) for the Final Rule titled, "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," published on October 1, 2019"

Date: September XX, 2020

Summary:

This document summarizes PHMSA's response to substantive public comments received on the first batch of Frequently Asked Questions (FAQs) for the Final Rule entitled "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments" (84 FR 52180), issued on October 1, 2019.

The FAQs were not deemed "significant" or "otherwise of importance to the Department's interests" as defined by 49 CFR 5.37. However, PHMSA voluntarily published these FAQs in the Federal Register on January 29, 2020, to solicit public comment under docket number PHMSA-2019-0225. PHMSA considered comments made at the public meeting on February 27, 2020, along with the eighteen public comments posted on the docket as of March 30, 2020, in finalizing the FAQs. Most comments received echoed joint comments submitted by the following trade associations: American Gas Association, the American Petroleum Institute, the American Public Gas Association, and the Interstate Natural Gas Association of America, which are summarized after each of the originally proposed questions FAQs below.

As noted below, some of the FAQs were revised in response to the comments. The revisions do not compromise pipeline safety, rather, they are intended to help pipeline operators navigate the published regulatory requirements and, where needed, clarify PHMSA's expectations for compliance. This document as well as the final version of Batch-1 FAQs will be placed in the same docket, PHMSA-2019-0225. The final version of Batch-1 FAQs will also be placed on PHMSA's guidance website.

General FAQs

FAQ-1. What are key implementation dates associated with this Final Rule?
Comment: Commenters noted that some of the code sections may not require a specific procedure. For example, §§ 192.67 and 192.127 involve material and design record retention requirements, and neither §§ 192.13(c) nor 192.605 require the operator to establish procedures associated with materials or design. They also commented that the prioritization schedule for completing § 192.710 is likely to change significantly during the first few years. Operators will perform initial moderate consequence area (MCA) identification through July 1, 2021, and this will change the risk prioritization and schedule. Assessments already scheduled for the current

year (2020) will likely include Class 3 and 4 and MCA mileage, but these will not necessarily be the highest risk because MCAs are still being identified. Commenters also asked for affirmation that spike hydrotesting is not required to reconfirm the MAOP under § 192.624.

PHMSA Response: PHMSA agreed with the comments and adopted the suggested clarifications. PHMSA concurs that early MAOP reconfirmation tests in Class 3 and 4 areas may not be using a "fully informed" risk-based approach since identification of MCAs and piggable segments may not be complete. The first round of MCA identification is still required to be completed by July 1, 2021. For additional details on that see FAQ-12. The first revised annual report to include MCAs and other new regulatory requirements will be March 15, 2022. PHMSA recognizes spike testing is not required (but may be used) for MAOP reconfirmation per 192.624(c). However, if a spike hydrotest is used to comply with Subpart O and § 192.710, those tests must comply with § 192.506. We revised the response to read "applicable" regulations to account for the varied procedures operators may need depending on their specific systems.

FAQ-2. Do any of the new rules apply to regulated gas gathering lines?

No significant comments. No material changes made to draft answer.

FAQ-3. Who qualifies as a "subject matter expert" for purposes of reviewing and validating failure pressure analyses under § 192.712?

No significant comments. No material changes made to draft answer.

FAQ-4. What date or what activities should an operator use to compute the beginning of the five-year period from which it needs to retain individual joining or welding qualification records pursuant to § 192.227(c)?

No significant comments. No changes made to draft answer.

FAQ-5. Removed. Why was the 2010 edition of NACE Standard Practice 0102, "In-Line Inspection of Pipelines" incorporated by reference in the Final Rule and not the 2017 edition?

PHMSA removed FAQ-5 because we do not want to comment on potential rulemaking actions.

Consideration of Public Comments on Batch- 1 Frequently Asked Questions (FAQs) on Gas Transmission Final Rule

Docket Number PHMSA-2019-0225

Reporting FAQs

FAQ-6. When is the effective date of the revised incident report form? (The revised form requires collecting data on the MAOP reconfirmation method and moderate consequence area location for the pipe segment involved in an incident.)

Comment: PHMSA received multiple comments to clarify when MCAs must first be reported on the incident report form. In the draft FAQs, PHMSA indicated that the revised incident form (Form PHMSA F 7100.2) would be available for use by the effective date of the gas transmission rule (i.e., July 1, 2020). Therefore, operators must identify if an incident occurred in a MCA starting July 1, 2020.

Industry indicated that MCA analysis was not due until July 1, 2021, a year after the implementation of new incident reporting form that requires documenting whether an incident occurred in an MCA. As such, operators may need to report the MCA status as "unknown" until July 1, 2021.

PHMSA Response: PHMSA revised its initial response. Operators can report new data requirements on the revised incident form (Form PHMSA F 7100.2) starting July 1, 2021. PHMSA further elaborated that the proposed incident form is on the docket (Form PHMSA-2019-0225).

FAQ-7. When will Form PHMSA F 7100.2-1 (annual report) be revised to reflect the additional information that PHMSA expects to collect for miles of pipe in MCAs and MAOP reconfirmation?

Comment: Commenters stated that PHMSA should consider delaying the implementation of the revised annual report until the 2021 reporting year (due in March 2022). In the draft FAQs, PHMSA stated that the revised annual report form (Form PHMSA F 7100.2-1) for gas transmission pipelines that will collect MCA and MAOP reconfirmation information will be available by July 1, 2020, and operators would be required to use the revised annual report form beginning for Calendar Year 2020, due no later than March 15, 2021. Industry did not believe that this draft response was correct.

The Final Rule, commenters stated, requires operators to develop and document procedures that will be used to reconfirm the MAOP of pipeline segments, which includes identifying which pipeline segments are in MCAs, by July 1, 2021. Many of the comments recommend that the new annual report go into effect after this date—once operators have defined which pipeline segments are MCAs and can accurately provide mileage and testing information.

Industry added that collecting data for the regulations on the 2020 annual report (due March 2021) creates a significant regulatory burden with limited value, as operators will be required to assemble and submit partially complete data sets. The commenters said they do not believe that this incomplete data would serve a useful purpose for PHMSA or the public. The commenters recommended that the revised report go into effect for the 2021 reporting year (due in March 2022), after operators have been required to identify those pipeline segments that are subject to the requirements of the Final Rule.

PHMSA Response: PHMSA agreed with the commenters. PHMSA revised its response and will require operators to use the revised annual report form beginning Calendar Year 2021, due no later than March 15, 2022.

Other Technology Notification FAQs

FAQ-8. Does the notification process set forth in § 192.18 apply to all of Part 192?

Comment: Commenters recommended removing this FAQ because § 192.18(a) states "any notification required by this part.…"

PHMSA Response: PHMSA did not remove FAQ-8 because the reporting requirements under § 192.18 did not fully list all the triggering events where notifications under § 192.18 are required to be reported. For example, operators are also required to notify PHMSA of changes to their Operator Qualification and Integrity Management plans per § 192.805(i) and § 192.909 (b), respectively.

FAQ-9. May operators submit a § 192.18 notification to PHMSA prior to the effective date of the rule (July 1, 2020)?

PHMSA removed this question in its final FAQ because this date has passed.

FAQ-10. Must operators wait for written approval from PHMSA prior to implementing other technology for purposes of complying with the sections identified in § 192.18(c)?

No significant comments. No material changes made to draft answer.

Moderate Consequence Area (MCA) FAQs

FAQ-11. In identifying MCAs affecting their pipelines, where can operators obtain information as to the location of a designated interstate, other freeway or expressway, and other principal arterial roadway with 4 or more lanes?

Comment: Commenters noted that "dedicated access road" is not a term defined in FHWA's Highway Functional Classifications and that it was unclear what PHMSA meant by "dedicated access roads." Commenters also stated that "frontage roads" should not be considered part of mainline highway for purposes of MCA analysis. The commenters stated that frontage roads are local roads that run parallel to a higher-traffic and higher-speed mainline roadway, and therefore would be outside of the "edge of pavement" of the mainline interstate freeway, expressway, or other principal roadway. Industry pointed out that the FHWA's Functional Classification Concepts, Criteria, and Procedures indicate that frontage roads are classified separately from the mainline highway. Finally, the commenters stated that PHMSA should work with FHWA to develop a map of roadways that would trigger an MCA, and that this approach was recommended by the GPAC and is consistent with PHMSA providing an Unusually Sensitive Area (USA) map for liquid pipelines.

PHMSA Response: PHMSA partially agreed with the commenters' position and removed the term "dedicated access road" and "frontage road" from its final FAQ-11. PHMSA has clarified that medians between applicable roadways need to be included in the MCA analysis. PHMSA also explained that entrance and ramps, which were integral to the operation of the covered highway function classifications, also need to be identified in the MCA analysis.
Regarding the suggestion that PHMSA work with FHWA to develop a map of roadways to trigger MCAs, PHMSA has not been directed to work with FHWA to designate federal highway classifications.

FAQ-12. When must operators complete the initial determination of MCAs on their pipeline system?

Comment: The draft FAQs stated that operators must complete the initial determination of MCAs on their pipeline systems by July 1, 2020, in order to comply with incident and annual report requirements. The commenters pointed out that the initial MCA analysis on pipe segments operating greater than or equal to 30% SMYS must be completed no later than July 1, 2021, not July 1, 2020.

Commenters added that an operator may choose to voluntarily designate all non-HCA Class 1 and Class 2 segments as MCAs in order to avoid a separate MCA analysis. An operator is not required to perform an MCA analysis for pipeline segments within an HCA.
Commenters also pointed out that saying operations must begin performing assessments according to a risk-based prioritization schedule after the effective date of the rule (July 1, 2020), could imply that the first assessment must take place precisely on July 1, 2020. The final rule prescribes deadlines, not start dates. Industry commented that operators' risk-based prioritization is expected to change as MCAs are identified and risk is evaluated in advance of the July 1, 2021, deadline for initial MCA analysis. Commenters said that operators may use prior assessments as initial assessments in accordance with § 192.710(b).

PHMSA Response: PHMSA's answer in the original draft FAQ was incomplete and needed to be clarified with respect to the due date of the first complete MCA analysis and future assessments of non-HCA pipeline segments. Operators must ***begin*** to develop procedures for MCA identification by July 1, 2020. Operators must ***complete*** the first round of MCA identification by July 1, 2021. Expectations for risk based assessment were added.

FAQ-13. Do operators need to identify, document, and track "unpiggable" MCAs operating less than 30% Specified Minimum Yield Strength (SMYS)?

Comment: Commenters suggested that PHMSA should only require MCA identification and related reporting for pipelines with an MAOP that produces a hoop stress that is greater than or equal to 30% of SMYS. The commenters reasoned that the MCA-related requirements in the new regulations are restricted to pipelines with an MAOP that produces a hoop stress greater than or equal to 30% of SMYS. The commenters contended that including pipeline segments with an MAOP less than 30% of SMYS in the MCA data produces little value because the new regulations do not require any action for these segments that would not otherwise be required for a non-MCA segment. Therefore, the commenters suggested, PHMSA's MCA dataset should align with the regulatory actions required for pipelines in MCAs.

PHMSA Response: PHMSA disagrees with the commenters' position. MCA identification for transmission lines is important for accident reporting and for determining what percentage of total MCAs are covered by the new regulation. No changes were made to the draft answer.

FAQ-14. How frequently must a re-evaluation of MCAs be performed and when must new MCAs be incorporated into an operator's plans and procedures?

Comment: Commenters recommended removing this FAQ. They acknowledged that operators must periodically re-evaluate MCAs, but stated that the Final Rule does not prescribe an annual review.

PHMSA Response: The annual update for MCAs is consistent with the HCA-identification frequency that has been employed by industry since the 2000s. Annual MCA identification updates are needed to ensure timely identification of new MCAs so that newly identified "consequence" risks to public safety can be quickly addressed. No changes were made to the draft answer.

Spike Hydrostatic Testing FAQs

FAQ-15. Under § 192.506 *Transmission lines: Spike hydrostatic pressure test*, is a spike test required for all pipelines that are hydrotested or re-hydrotested and are operating at 30% or more of SMYS? For what threats is a spike hydrostatic pressure test appropriate?

Comment: Commenters stated that spike testing is only appropriate for certain time-dependent threats and not all time-dependent threats (e.g., spike testing is not required for pipe body corrosion). Commenters also pointed out that spike testing is only appropriate for certain manufacturing threats.

PHMSA Response: PHMSA agreed with the suggestion that spike hydrostatic pressure testing is required for only certain time-dependent or manufacturing threats and not all time dependent threats as reflected in the draft FAQ-15. PHMSA chose against using the word "certain," opting instead to list the specific applicable regulations that may require a spike hydrotest.

Material Verification FAQs

FAQ-16. Is the use of § 192.607 Verification of Pipeline Material Properties and Attributes allowed outside of HCAs, MCAs, and Class 3 and Class 4 locations?

Comment: Commenters stated that references to § 192.607 are in § 192.624(c) and § 192.632, which specify certain methods for performing MAOP reconfirmation. The MAOP reconfirmation requirements do not apply to Class 1 and 2 segments outside of HCAs and MCAs.

That said, several commenters noted that the intent, as expressed by PHMSA during meetings on the Rule, was to allow operators the option of using § 192.607 to determine Subpart C-Pipe Design attribute*s* outside of HCAs, MCAs, Class 3 and Class 4 locations. The commenters reminded PHMSA that in the preamble of the Final Rule, PHMSA stated, "…PHMSA hopes that operators will use [§ 192.607] for material properties verification even when not specifically required by Part 192 because it provides a common-sense, opportunistic, and practical approach for gathering the records necessary to substantiate safe MAOPs, properly implement IM, and otherwise ensure the safe operation of the nation's pipeline network."

The commenters believe that PHMSA should be clear that the TVC requirement for MAOP records applies only to segments subject to § 192.624. Operators must determine MAOP in accordance with § 192.619(a)(1)-(4) or § 192.619(c). The TVC standard for MAOP records does not apply to Class 1 and 2 segments outside of HCAs and MCAs. They also said PHMSA should not require operators to request a special permit to apply the § 192.607 material verification process to re-establish MAOP outside of HCAs, MCAs, and Class 3 and Class 4 locations when there is an existing process in Part 192 that is a "common-sense and practical" approach. Lastly, commenters noted that PHMSA should not discourage voluntary safety work nor should PHMSA seek to regulate individual operators via one-off special permits.

Commenters stated that the second group of references to § 192.607 are in § 192.712, which establishes requirements for analyzing predicted failure pressure of discovered anomalies. Operators are required to repair anomalies that impair the serviceability of a pipeline, including on pipelines outside of HCAs, MCAs, and Class 3 and Class 4 locations, under existing §§ 192.485, 192.711, and 192.713. Therefore, operators may apply § 192.712 and § 192.607 when evaluating anomalies outside of HCAs, MCAs, and Class 3 and Class 4 locations.

PHMSA Response: Considering these comments, PHMSA's statements during the meetings on this Rule and the Preamble to the Final Rule, PHMSA revised its answer to FAQ-16. The verification of pipeline material properties under § 192.607 applies when specifically referenced in Part 192, and may voluntarily be used (without the need for an approved Special Permit) for material property verification outside of HCAs, MCAs, and Class 3 and Class 4 locations in order to determine key Subpart C – Pipe Design attributes. Sections 192.619(a)(4), 192.624, and 192.712 requires the usage of § 192.607, when material properties are unknown. PHMSA did not address the need for materials attributes outside of HCAs, MCAs, Class 3, and Class 4 areas to be TVC since it is not required unless in the future those pipe segments did fall within one of those areas needing MAOP reconfirmation.

FAQ-17. PHMSA allows the data collection process to be accomplished "opportunistically" per § 192.607(c). Is there a deadline by which operators are expected to complete this process?

Comment: Commenters stated that the opportunistic gathering of data on unknown material properties does not need to meet the Final Rule schedule in §192.624(b) because material verification may also be used to comply with § 192.712. The commenters pointed out that for anomaly evaluation purposes under § 192.712, the timeframe for such opportunistic data collection may vary based on the length of pipeline, amount of pipe with missing material properties, number of opportunities, and testing results gathered § 192.607

PHMSA's Response: PHMSA agrees and revised the FAQ to acknowledge that the gathering of material properties is an "opportunistic" approach that may be used to satisfy § 192.624, as well as § 192.712. Material properties, when unknown, must the gathered wherever the pipeline is excavated as defined in § 192.607(c). The data collection process for material properties must be completed however prior to completing the reconfirmation method if that method requires material properties.

FAQ-18. When determining separate pipe "populations" for conducting a verifiable material properties and attributes sampling program that satisfies § 192.607(e)(1), must an operator compare the dates of manufacture and construction together, or must the manufacture and construction dates be compared separately? For example, would two segments of pipe that were manufactured in the same year but were installed together, 3 years after manufacture, be in the same population? As a second example, would two segments of pipe that were manufactured in the same year but installed 3 years apart be in the same population?

Comment: Commenters stated that the construction date has no impact on the material properties of the pipe. Therefore, manufacturing and construction dates can generally be used interchangeably. The commenters stated that in scenarios where all other parameters are the same but manufacturing date of the pipe is not available, the construction date could be used as a proxy for the manufacturing date for the purpose of determining a population.

PHMSA Response: PHMSA disagrees. PHMSA does not believe that the construction date is a valid proxy for the manufacturing date because material attributes are directly tied to the manufacturing date. No substantive changes were made to the Final FAQ-18.

FAQ-19. It appears to be a requirement to separate pipe segments into different populations based on the material properties and attributes listed in § 192.607(e)(1), but how do you handle the situation where you are missing documentation for an attribute like pipe manufacturing dates?

No significant comment. No changes made to draft answer.

FAQ-20. How should operators define populations where necessary documentation is missing? Can an operator group all pipe sections with unknown attributes into one population?

No significant comment. No material changes made to draft answer.

FAQ-21. Can the data from in-line inspection tools be used to help determine population groups under § 192.607(e)?

No significant comment. No material changes made to draft answer.

FAQ-22. Can an operator use SMYS, wall thickness and seam type derived from in-line inspection tools for material verification under § 192.607(c)?

No significant comment. No material changes made to draft answer.

FAQ-23. Is there a process to compile comparable pipe material properties across the industry?

Comment: Commenters recommended removing this FAQ because efforts are underway to produce industry-wide datasets of pipe properties for similar-vintage pipe. The commenters noted that although operators are responsible for implementing their own material verification program, an industry-wide dataset could be a beneficial resource in support of individual operators' programs.

PHMSA Response: PHMSA disagrees with the recommendation to remove this FAQ. PHMSA is not aware of a process to compile pipe material property information. PHMSA continues to expect operators to determine the attributes of pipe materials specific to individual pipeline system(s).

FAQ-24. During which type of pipeline exposures does an operator need to perform material properties and attributes verification?

Comment: Several commenters stated that it may not always be appropriate or practical to verify material properties at the first available excavation. They urged PHMSA to clarify that operators' procedures must establish specific criteria for identifying which excavations are appropriate "opportunities" for material verification and identify any criteria that would render an excavation inappropriate for material verification (e.g. safety concerns such as immediate repairs, equipment availability, service interruption, supply constraints, out of service time limitations).

PHMSA Response: PHMSA's draft FAQ-24 aligned with this recommendation. Additional clarifying language was added to the final FAQ-24 regarding that safety overruled immediate material attribute testing.

FAQ-25. If an operator has unknown material properties and during normal operations excavates a leak on a transmission line operating at less than 30% SMYS, must it perform a destructive or nondestructive test to verify material properties?

Comment: The commenters concurred with PHMSA's answer in FAQ-25, but requested PHMSA clarify that an operators' procedures may establish criteria for identifying situations where a repair-related excavation is inappropriate for material verification (e.g. safety concerns such as immediate repairs, equipment availability, service interruption, supply constraints, out of service time limitations, etc.).

PHMSA Response: PHMSA agreed with the commenter's philosophy that explicit procedures are needed to identify situations when a repair-related excavation is unsafe, and destructive or nondestructive (in-situ) testing is not immediately required. PHMSA did not agree that equipment availability, service disruption, or out of service limitations were good examples of blanket exemptions from opportunistic testing for material properties. PHMSA clarified in its response that an area should be made safe before performing testing to verify pipeline material properties.

FAQ-26. In accordance with § 192.607, what pipe material properties or attributes must be verified through *in situ* (non-destructive) testing during an excavation and exposure of the pipeline?

Comment: Commenters suggested that PHMSA reword its answer by stating that operators test for strength or grade, wall thickness and seam type, and delete the words "chemistry" and "coating type."

PHMSA Response: PHMSA agrees with this suggestion because chemistry and coating type are not required for MAOP reconfirmation, per §§ 192.619 and 192.624.

FAQ-27. What are operators expected to do if they find material properties records that do not substantiate MAOP in Class 1 or 2 locations or in non-MCA/HCA segment while complying with § 192.607?

Comment: Commenters requested that PHMSA revise FAQ-27 to note that operators are not automatically required to reduce MAOP based upon one sample or one characteristic. Commenters contended that operators should first have an opportunity to conduct additional investigations such as expanded sampling in order to determine whether the pipeline is not adequate for the MAOP. In making this determination, commenters noted that operators should consider the accuracy of the material verification method used. Industry also said that some non-destructive methods are currently very conservative.

PHMSA Response: PHMSA believes that operators should reduce pressure until they can gather additional information to verify safety and that operators should comply with existing code. Therefore, no changes to the draft answer were made.

FAQ-28. What does PHMSA mean in § 192.607(e)(4) when it states that an operator must establish an expanded sampling program when it finds line pipe with properties "that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past?"

Comment: Commenters requested that PHMSA clarify that where an operator has used conservative assumptions/default values to determine MAOP (because material data was unavailable or incomplete) no additional testing is required where material verification confirms better material properties (e.g. stronger) than the conservative/default values. For example, for pipe with unknown grade, if an operator previously assumed the value of 24,000 psi allowed under 192.107, a material test that demonstrates a higher grade would be *consistent* with assumed properties.

Commenters also requested that PHMSA note that material properties are only "not consistent" based on specified properties, not based on actual properties. For example, if an operator identifies pipe with an actual yield strength higher than the specified minimum yield strength, no expanded sampling is required.

PHMSA Response: The comment was beyond the scope of this question. PHMSA will address the possibility of using higher conservative values in § 192.607(e)(4) in the draft Batch 2-FAQs. No substantive changes were made to the Final FAQ-28.

FAQ-29. Can I collect material information from Class 1 and 2 and non-MCA/non-HCA locations and apply it to segments that require material properties and attributes verification under § 192.607, assuming the pipe is similar? For example, can pipe material properties that are collected and validated for pipe examined outside of HCA, MCA, Class 3 and 4 locations be used if similar pipe is found in an HCA, MCA, Class 3 and 4?

Comment: Commenters stated that performing material testing in Class 1 and 2 and non-MCA/non-HCA location makes sense in certain situations. For example, if an operator is planning to comply with § 192.624 for a Class 3 pipe by performing material verification on the Class 3 pipe itself in conjunction with a hydrotest of that pipe, then there is no need to perform material verification on any Class 1 or 2 segments. However, performing material verification on Class 1 and 2 segments may be beneficial for anomaly evaluation purposes under § 192.712.

The commenters stated that operators should take advantage of all pipeline excavations and exposures to collect material properties, regardless of the pipeline location.

PHMSA Response: PHMSA agrees with the commenters and adopted the suggested language to clarify to industry that if they do use material information from outside HCA, MCA, or Class 3 or 4 areas using § 192.607 then they must abide by that regulation completely.

Maximum Allowable Operating Pressure Establishment and Reconfirmation FAQs

FAQ-30. What is meant by "traceable, verifiable, and complete in relation to MAOP records?

Comment: Commenters suggested that PHMSA confirm that a single quality record may be traceable, verifiable, and complete. The commenters stated that in a clarification letter to the American Gas Association in 2012 and during the March 26-28, 2018 GPAC meeting, PHMSA stated that "a single quality record" may be TVC. This clarification is important, as operators have been assessing and validating records for years under the assumption that a single quality record may be TVC.

PHMSA Response: PHMSA did not adopt the commenters' recommendation in its final FAQ-30. However, PHMSA did clarify what it expects to see in a single quality record that is also TVC in subsequent proposed guidance.

FAQ-31. What sources of information should operators use to discover segments that require MAOP reconfirmation under § 192.624 (i.e., segments that do not have traceable, verifiable, and complete MAOP records)?

Comment: Commenters suggested that PHMSA clarify that (1) § 192.624(a) defines when MAOP reconfirmation is required, and (2) MAOP reconfirmation is required where an operator does not have a TVC **pressure test record**, not where an operator is lacking a TVC record for other pipeline properties. Per PHMSA's response to the joint AGA/APGA/API/INGAA petition for reconsideration on December 20, 2019, the applicability of the MAOP reconfirmation requirements of § 192.624(a)(l) are limited to those pipeline segments that do not have a TVC **pressure test record** in accordance with § 192.619(a)(2). The commenters suggested that operators only need to review existing records that support or related to their pressure test records. If the pressure test records are incomplete or otherwise inadequate, then operator must reconfirm MAOP for those segments.

PHMSA Response: PHMSA rejected this suggestion because the original TVC pressure test record may not accurately reflect modifications that had been made in the pipeline system since the hydrotest or pressure test was performed. No substantive changes were made to the Final FAQ-31.

FAQ-32. If an operator does not have to reconfirm MAOP under § 192.624, what must it do if it does not have records necessary to establish the MAOP of a pipeline segment? Examples of pipelines that would not be covered under § 192.624 include Class 1 and 2 (non-HCA/non-MCA) onshore transmission lines.

Comment: Commenters requested that PHMSA clarify that the TVC requirement for MAOP records only applies to segments subject to §192.624(a). The commenters stated that the TVC standard for MAOP records does not apply to Class 1 and 2 segments outside of HCAs and MCAs. Commenters also suggested deleting "Alternatively, an operator may request, and upon PHMSA approval, must comply with a special permit allowing the Operator to rely on § 192.607 for pipelines not meeting §192.624 (a) criteria."

PHMSA Response: PHMSA agreed with the commenters that special permits are not required to use §192.607 in Class 1 or 2 locations. However, PHMSA disagrees with the suggestion that TVC records are not required in Class 1 and 2 segments outside of HCAs. Therefore, PHMSA clarified that TVC records are required to support MAOP in Class 1 and 2 locations and listed the records that must be included as part of either MAOP determinations required in § 192.619(a) or anomaly evaluations in § 192.712.

FAQ-33. Can an operator take a pressure reduction per § 192.624(c)(2) and not have to reconfirm MAOP?

Comment: Commenters stated that if operators have reduced their MAOP under §192.624(c)(2), they have complied with § 192.624. Moreover, commenters stated that no further § 192.624 or §192.632 action is required unless the operator wishes to reverse the pressure reduction.

PHMSA Response: Draft FAQ-33 aligns with the comments. No substantive changes were made to the Final FAQ-33. PHMSA did not address the comment regarding reversing a past pressure reduction through MAOP reconfirmation since it was not within the scope of this question.

FAQ-34. Methods 2 and 5 under § 192.624(c), which permit reconfirming MAOP based upon the highest actual operating pressure during the 5 years preceding October 1, 2019, what does "the highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period" mean?

No significant comment. No material changes made to draft answer.

FAQ-35. After July 1, 2021, if an operator discovers a pipeline segment that meets the applicability criteria under § 192.624 due to a change in class location, when must the operator confirm or revise the MAOP for that segment?

Comment: Commenters stated that when records are discovered that cause pressure test records for a pipeline segment to not be TVC, reconfirmation of MAOP must be performed in accordance to § 192.624(b)(2).

PHMSA Response: PHMSA clarified that the MAOP must be established per §§ 192.609 and 192.611, and not per § 192.624(b)(2) in the draft FAQ-35. No substantive changes were made in the Final FAQ-35.

FAQ-36. If a pipeline is operating at greater than 72% SMYS with a "legacy" MAOP (i.e., established according to § 192.619(c)) and experiences a change in class location from Class 1 to Class 2 or from Class 1 to Class 3, can an operator use § 192.624 to confirm the MAOP?

Comment: Commenters recommended that PHMSA delete the sentence stating that "if the pipeline is operating at corresponding hoop stress that is commensurate with the present class location, the existing grandfathered MAOP can be maintained, assuming the grandfathered MAOP is document (per §§ 192.603(b) and 192.605 (b)(3) and material properties, pipe design and pipe component records are traceable, verifiable, and complete."

PHMSA Response: PHMSA disagrees with the suggestion that legacy pipe can continue operating above 72% SMYS with a hoop stress that is not commensurate with its new class location. PHMSA revised FAQ-36 to provide additional details explaining why a "legacy" MAOP losses its ability to operate over 72% SMYS when a class location change occurs.

FAQ-37. Is MAOP reconfirmation required for non-line pipe and components within appurtenant facilities, including compressor, meter, and pressure-limiting stations?

Comment: Commenters noted that the final rule does not explicitly address MAOP reconfirmation for facilities/fabricated assemblies, such as compressors, pressure-limiting stations, and meter stations. Commenters suggested that PHMSA confirm that § 192.624 only applies to "pipeline segments" and not facilities/fabricated assemblies. Commenters believe that: 1) § 192.624 does not apply to piping that would be subject to design factors for fabricated assemblies or station piping under §192.111; 2) under §192.607(f), testing of components for chemical and mechanical properties is not required; and 3) per § 192.607(f), for components outboard of appurtenant facilities and stations, verifying the component manufacture's stamped, marked, or tagged material pressure ratings and material type will be sufficient for MAOP reconfirmation when an operator selects a method under § 192.624(c) that requires material verification.

PHMSA Response: PHMSA agrees that clarification is warranted but disagrees with the commenters conclusion that § 192.624 does not apply. As noted in the draft FAQ-37, line pipe and non-line pipe within compressor, meter, and pressure-limiting stations (up to the station emergency shutdown or isolation valves) are subject to § 192.624 and must be incorporated into the operator's MAOP reconfirmation program in draft FAQ-37. Additional clarification was added to the final FAQ-37 regarding testing and delineation of where testing of components is required.

FAQ-38. Must material property and MAOP reconfirmation records be retained after a pipeline has been abandoned?

No significant comment. No material changes made to draft answer.

FAQ-39. When performing a pressure test as an assessment in accordance with §§ 192.710, 192.917(e), and 192.921, what are the allowable test media?

Comment: FAQ-39 originally asked "[m]ust water be used for pressure test to address manufacturing and construction defects. PHMSA answered yes and stated that operators must follow § 192.503 requirements when conducting future pressure tests. Several commenters noted that the answer should have been no. Commenters noted that Subpart J allows for testing with liquid, air, natural gas, or inert gas and provides the requirements and limitations for each, but that the newly revised § 192.917 (e)(3), which requires pressure test with water, only applies to pipelines subject to Subpart O. Therefore, commenters suggested that PHMSA clarify that the Final Rule requires operators to use water prospectively for future pressure tests to confirm manufacturing and construction defect stability in HCAs. Commenters also requested that PHMSA clarify that this change does not invalidate tests conducted in accordance with Part 192 with media other than water prior to the Final Rule.

PHMSA Response: PHMSA concurs with industry's position but thought further clarification of appropriate mediums for both HCA and non-HCA testing was needed in our response. PHMSA clarified its position regarding test mediums that could be used for assessments, and the fact that previous assessments were not invalidated in HCA areas unless one of the events listed in 192.917 (e)(3) occurs.

Failure Mechanics FAQs

FAQ-40. What failure or fracture mechanics models can be used to analyze predicted failure pressure under § 192.712?

No significant comment. No material changes made to draft answer.

Consideration of Public Comments on Batch- 1 Frequently Asked Questions (FAQs) on Gas Transmission Final Rule

Docket Number PHMSA-2019-0225

Assessments Outside of High Consequence Areas FAQs

FAQ-41. If Charpy v-notch assumptions are used as provided in § § 192.712(e)(2)(i)(c) and (D), does Charpy v-notch testing need to be performed to verify material properties?

Comment: Commenters stated that an operator should obtain the undocumented data "opportunistically," through § 192.607.

PHMSA Response: PHMSA does not agree with the comment because Charpy v-notch assumptions should only be used in the short-term before actual values are determined. Regardless, accurate Charpy v-notch values are required to perform accurate anomaly evaluations. No changes to Final FAQ-41 were made.

FAQ-42. What are the response timeframes for anomalies discovered in MCAs?

Comment: Commenters suggested that PHMSA state that it expects operators to take remedial measures for anomalies identified in MCAs after July 1, 2020, in accordance with § 192.710(f).

PHMSA Response: PHMSA did not include a date in its final FAQ because the regulation in the current rule does not establish one. No substantive changes were made to Final FAQ-42.

FAQ-43. Are the assessments required by § 192.710(b)(2) to be performed once every 10 calendar years with intervals not to exceed 126 months or once every ten years (120 months) with intervals not to exceed 126 months?

No significant comment. No material changes made to draft answer.

FAQ-44. What is the required reassessment interval for a pipeline segment containing both HCAs and MCAs?

Comment: Commenters suggested that PHMSA state that the required reassessment interval for a pipeline segment containing both HCAs and MCAs is once every seven calendar years in accordance with § 192.939 (a), assuming the operator wishes to assess the entire segment in a single assessment. Otherwise, the operator may test only the MCA portion in accordance with the schedule specified in §192.710.

PHMSA Response: PHMSA agrees with the comment and expanded upon its original response to clarify that it expects pipeline segments containing both MCAs and HCAs to comply with the shorter HCA assessment interval of seven years.