

Draft Frequently Asked Questions (FAQs) on Gas Transmission Final Rule

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Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety

Title: Draft “Frequently Asked Questions 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: January 30, 2020

Summary:

This draft guidance document is issued to assist owners and operators of gas transmission pipelines subject to the pipeline safety standards in 49 CFR Part 192. Those rules 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 This draft guidance is being published for public comment and is not intended to replace or revise any previously issued guidance.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 intended only to provide clarity to the public regarding 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 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 (if spike testing is being performed outside of Maximum Allowable Operating Pressure (MAOP) reconfirmation), 192.517, 192.607 (if material verification is being used outside of MAOP reconfirmation), 192.619, 192.710, 192.712, 192.805, 192.909, 192.917, 192.921, 192.933, 192.935, 192.937, 192.939, and Appendix F to Part 192.
- Begin to identify, schedule (according to a risk-based prioritization), and perform assessments required by § 192.710.

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July 1, 2021

- Begin retaining records for each individual welder qualification at the time of construction in accordance with § 192.227 for a minimum of 5 years following construction.
- For transmission pipe installed after July 1, 2021, begin retaining records for each person's plastic pipe joining qualifications at the time of construction in accordance with § 192.285 for a minimum of 5 years following construction.
- Operators subject to § 192.624 must develop and document procedures for completing all actions required by this section. 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 in accordance with §§ 192.506 and 192.607, if applicable.
 - A process for performing an engineering critical assessment (ECA) for MAOP reconfirmation in accordance with § 192.632, if implemented.
- Any launcher or receiver used after this date must meet the conditions of § 192.750.

July 3, 2028

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

July 3, 2034

- Complete all originally identified assessments required by § 192.710.

July 2, 2035

- 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 gas gathering lines?

Yes. While the new rules are written with a focus on the safety of onshore gas transmission lines, there are new requirements that apply to gas gathering lines. Section 192.9 includes a list of specific code sections not applicable to gas gathering lines. Operators of gas gathering lines should review the following code sections, which were revised in this rulemaking, as applicable 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?

The intent of § 192.712 is to require that operators conduct failure pressure analyses that are rigorous, reviewed and confirmed by qualified experts, and properly documented. While such analyses do not necessarily need to be performed by a subject matter expert, at least they need to be reviewed and

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evaluated by a qualified subject matter expert. PHMSA describes its expectations as to who qualifies as a “subject matter expert” in the Preamble of the 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.

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)?

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. Construction-related activities, such as painting, final right-of way grading and clean up, and environmental mitigation, may continue after the pipeline has been placed in service.

FAQ-5. 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?

The Notice of Proposed Rulemaking was noticed in April of 2016 but the 2017 edition of NACE Standard Practice 0102, “In-Line Inspection of Pipelines” had not yet been published. The 2017 edition will be considered for incorporation by reference in a future rulemaking.

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.)

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 detection of an incident that is required to be reported under § 191.5 of Part 191. The form has been modified to collect information and data that the pipeline operator must obtain as part of the Final Rule.

The revised incident form (Form PHMSA F 7100.2) will be available for use by the effective date of the gas transmission rule (i.e., July 1, 2020). The revised report has been modified to record the 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 for determining the applicability of new requirements under §§ 192.624(a) and 192.710(a).

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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 that will collect MCA and MAOP reconfirmation information will be available by the effective date of the gas transmission rule (i.e., July 1, 2020). PHMSA will require Operators to use the revised annual report form beginning for Calendar Year 2020, due no later than March 15, 2021. 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. Unless otherwise noted, the process set forth in § 192.18 is available only for those sections specifically identified in § 192.18(c), 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).

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

Yes. Operators are encouraged to submit a notification pursuant to § 192.18 at any time, so long as the notification is submitted to PHMSA at least 90 days prior to the operator implementing “other technology” that differs from that prescribed in the sections set forth in § 192.18(c) for purposes of compliance with those sections.

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. Written approval or a “no objection letter” from PHMSA is not necessary to proceed with the use of “other technology” for compliance with the sections set forth in § 192.18(c) so long as the operator properly submitted a § 192.18 notification and 90 days have passed since the submittal with no response from PHMSA.

If an operator wants a written “no objection letter” from PHMSA prior to implementing the alternative technology for compliance with those sections set forth in § 192.18(c), the operator should include a specific request for such a written response in its § 192.18 notification.

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Moderate Consequence Area (MCA) FAQs

FAQ-11. In identifying MCAs affecting their pipelines, where can Operators obtain information as to the location of interstate highways, freeways or other expressways, and other arterial roadways?

PHMSA expects Operators to use all information available including but not limited to 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 to identify applicable roadways. When identifying an MCA, PHMSA expects Operators to capture the area between the outside paved surfaces, to include all median lengths. Dedicated access roads and ramps to these FHWA-defined 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/fcaua_b.pdf). Section 4 of the FHWA document does, however, include recommendations and guidance on how to obtain GIS-based roadway inventory data at a State level.

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

Operators must develop and implement procedures for determining the location of MCAs on their pipeline system and incorporate them into their manual for maintenance and normal operations beginning on the effective date of the rule per § 192.605(b)(1). The locations of MCAs are required for operators to complete the revised incident and annual reports that will be available on or before the effective date of the rule, July 1st, 2020 (see FAQ-6 and FAQ-7).

PHMSA anticipates some operators to incorporate the MCA identification process into their existing HCA and class identification procedures while other Operators might perform a separate analysis. MCAs are used in determining a pipeline segment's applicability under §§ 192.624 (MAOP reconfirmation) and § 192.710 (assessments outside of high consequence areas (HCAs)).

Operators must begin performing assessments according to a risk-based prioritization schedule starting on the effective date of the rule (July 1, 2020) with 100% completion in 14 years, per § 192.710. Additionally, Operators must begin performing MAOP reconfirmation on July 1, 2021 to complete all actions required by the schedules in § 192.624(b)(1) and (2).

FAQ-13. Do Operators need to identify, document, and track “unpiggable” MCAs operating less than 30% SMYS?

Yes, all MCAs, regardless of piggability and operating stress need to be identified, documented, and tracked for annual and incident report data collection.

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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 (§§ 192.905 and 192.609). An Operator must add any newly identified MCAs to its § 192.710 assessment schedule within 1 year of the discovery date. This is consistent with current Gas IMP FAQ-19, FAQ-20, and FAQ-179 posted to 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 SYMS.

A spike test is appropriate and should be considered for time-dependent threats, such as 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 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% specified minimum yield strength (SMYS), then the test must be conducted according to the spike-test procedures in § 192.506.

Material Verification FAQs

FAQ-16. Does § 192.607 apply outside of HCAs, MCAs, and Class 3 and Class 4 locations?

No. The verification of pipeline material properties under § 192.607 applies only where it is explicitly referenced in Part 192. In locations where material properties are unknown and § 192.607 does not apply, Operators must use the design formula for steel pipe in Subpart C – Pipe Design to determine the design pressure and MAOP (see § 192.619(a)).

PHMSA would consider, as part of a special permit request, the use of § 192.607 for material property verification outside of HCAs, MCAs, and Class 3 and Class 4 locations in lieu of Subpart C – Pipe Design. Operators must continue to use Part 192, Subpart C to gather pipe material attribute data or use assumed conservative material values for pipe segments that are not in an HCA, MCA, or Class 3 and 4 location.

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FAQ-17. For applicable pipelines, as defined by § 192.624(a), and for which an Operator has insufficient material property records, PHMSA allows the data collection process to be accomplished incidental to routine repairs and maintenance, or “opportunistically,” under § 192.607(c). Is there a deadline by which Operators are expected to complete this process? For example, would it need to be completed by the Final Rule’s schedule for MAOP reconfirmation (50% by 7/3/2028 and 100% by 7/2/2035)?

No. The opportunistic gathering of data on unknown material properties does not need to meet the Final Rule schedule in § 192.624(b). The timeframe for such 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 complete description.

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 another 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), 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). For the first example, the two pipe segments would be in the same population but in the second, they would not.

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 that have documentation for pipe material properties but are missing the manufacturing or construction date attribute would not need to conduct an expanded sampling program to determine material properties. Manufacturing and construction dates noted in § 192.607(e)(1) and FAQ-18 are used to delineate the boundaries of the material properties sampling program when complete material properties are unknown.

Operators should only split populations based on known attributes, and have separate populations of pipe segments where attributes are unknown. Operators must sample where material attributes are unknown.

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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. Based on the sampling program's results, an Operator must add new verified samples into existing matching pipe populations or create new pipe populations from those samples, if 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 what processes they use to implement the requirements of MAOP reconfirmation and material verification, and whether an alternative sampling approach under § 192.607(e)(5) is utilized.

FAQ-22. Can an Operator use specified minimum yield strength (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, certain material properties and attributes can be determined with the required confidence levels. Per § 192.607(d), nondestructive testing must use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage.

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

No, there is currently no process to compile pipe material property information. Material properties can vary greatly during the manufacturing process. PHMSA expects Operators to verify pipe material that is 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 conducting nondestructive or destructive tests, examinations, and assessments to verify the material properties. The listed activities are: anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. PHMSA does not expect, but encourages, if feasible and does not delay or interrupt the one-call excavation, Operators to perform material verification for unknown pipe properties on pipeline segments exposed during one-call excavations initiated by third parties.

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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?

Yes, if the Operator needs material properties and attributes. In general, material verification testing under § 192.607 is required due to applicability of § 192.624 or as needed per § 192.712 *Analysis of Predicted Failure Pressure*.

FAQ-26. What pipe material properties or attributes must be determined through *in situ* (non-destructive) testing during an excavation and exposure of the pipeline?

Operators must test for strength, grade, or chemistry; wall thickness; seam type; and coating type, if these items are unknown and are necessary for MAOP reconfirmation (§ 192.624), an engineering critical assessment (§ 192.632), or failure pressure analysis (§ 192.712), as specified by those regulations.

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

Operators will need to reduce the operating pressure and MAOP in accordance with § 192.619 and may need to perform MAOP Exceedance reporting in accordance with §§ 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 in their material verification procedures the term “not consistent” in this context and how it will establish an expanded sampling program in response to such information. The regulation requires an operator to maintain material records for line pipe: 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 are different from what is being used to determine the MAOP of the pipeline should consider such properties to be “not consistent” with available information and assumptions for operations and maintenance and 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. PHMSA expects Operators to take advantage of all pipeline excavations and exposures to collect material properties, regardless of the pipeline location. PHMSA expects the Operator to adopt and follow

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procedures for implementing § 192.607(e), specifically including what limits are placed on determining similar segments of pipe on a consistent basis, the tools being used, and the materials being validated.

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 includes 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

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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 existing records reflecting pipe replacements, relocations, repairs, or other changes to verify that those records have been integrated into their MAOP records. For example, records of historical repairs, leaks, ruptures, incidents, and in-line inspection data (wall thickness, coating, seam type, joint length, fittings, etc.) should be compared against the Operator's 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 regulated onshore gas gathering lines, distribution lines, and Class 1 and 2 (non-HCA/non-MCA) onshore transmission lines.

PHMSA requires Operators of pipelines that do not meet the applicability criteria of § 192.624(a) to comply with the other MAOP and design requirements of Part 192 (i.e., §§ 192.619(a), 192.105, 192.107(b)(2), 192.109, and 192.113). 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.

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 in accordance with "Method 2" of § 192.624(c)(2) *is* reconfirming the pipeline's MAOP by creating the safety margin by which the pipe is operating, and is creating and establishing a new MAOP. The recordkeeping requirements of § 192.619(f) will apply to the

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MAOP reconfirmation records that document the pressure reduction (i.e., 5-year operating pressures, application of reduction factors, etc.). Note, however, that if an Operator needs 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, or the calculation of predicted failure pressures, for example), the Operator would still need to obtain those records per the opportunistic method described at § 192.607.

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

This 8-hour period does not need to be continuous; it can be made up of a variety of time periods that over the course of a 30-day period 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 reconfirm the MAOP for that segment?

When a change in Class location occurs on a pipeline segment, confirmation or revision of the MAOP must be performed within 24 months of when the classification changes, in accordance §§ 192.609 and 192.611 and not in accordance with MAOP reconfirmation requirements in § 192.624(b)(2).

When a new HCA or MCA, or changes to an existing HCA or MCA on a pipeline segment make it subject to § 192.624(a), reconfirmation of MAOP must be performed in accordance with § 192.624(b)(2).

When records are discovered that cause MAOP records for a pipeline segment to not be traceable, verifiable, and complete, reconfirmation of MAOP must be performed in accordance with § 192.624(b)(2).

FAQ-36. If a pipeline is operating at greater than 72% SMYS with a grandfathered 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 pipeline segment (+72% SMYS) must be revised in accordance with §§ 192.611(a)(2) or (3). However, if the pipeline is operating at a corresponding hoop stress that is commensurate with the present class location, the existing grandfathered MAOP can be maintained,

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assuming the grandfathered 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 (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. 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, but 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?

Yes, Operators must follow § 192.503 requirements when conducting future pressure tests. If prior pressure tests utilized a medium other than water for manufacturing or stability threats, PHMSA would expect notification under § 192.18 if the test medium did not meet § 192.503 requirements.

Failure Mechanics FAQs

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

The failure or fracture mechanics models that can be used are listed in the Preamble of the rule at 84 FR 52236. All failure models used for the ECA analysis must be used within each model's technical parameters for the defect type and the pipe or weld material properties. If an Operator desires to use a method that is not listed, it 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, inline inspection (ILI), or other).

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

- For the brittle failure mode, the Newman-Raju Model¹ and PipeAssess PI™ software;² and

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>.

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- For the ductile failure mode, Modified Log-Secant Model,³ API RP 579-1⁴ – 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 in accordance with §§ 192.632, 192.712(d) through (g), and 192.713 (i.e. per the Operator’s determination of impaired serviceability).

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 ultimately needs to obtain Charpy v-notch values if they 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 the undocumented data through § 192.607. Until documented material properties are available, the Operator shall 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). PHMSA expects Operators to take remedial measures for anomalies in MCAs in accordance with § 192.710(f). Response timeframes for MCAs will be included in the final rule, “Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments” (PHMSA-2011-0023).

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(a).

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.

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

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).