BEFORE THE
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
WASHINGTON, D.C.

Frequently Asked Questions regarding "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments"	Docket No. PHMSA-2019-0225

COMMENTS ON "BATCH 2 GAS TRANSMISSION DRAFT FAQs"

FILED BY
AMERICAN GAS ASSOCIATION
AMERICAN PETROLEUM INSTITUTE
AMERICAN PUBLIC GAS ASSOCIATION
GPA MIDSTREAM ASSOCIATION
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

March 16, 2020

The American Gas Association (AGA),[1] American Petroleum Institute (API),[2] American Public Gas Association (APGA),[3] GPA Midstream Association,[4] and Interstate Natural Gas Association of America (INGAA)[5] (jointly "the Associations") (jointly "the Associations") submit these comments for consideration by the Pipeline and Hazardous Materials Safety Administration (PHMSA) concerning the draft "Batch 2" 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" (Final Rule).[6]

Pipeline safety is the top priority of the Associations and our members. The Associations strongly support the Final Rule, which will enhance pipeline safety and help advance our industry's efforts to achieve a perfect safety and reliability record for our nation's natural gas pipelines. The Associations have publicly championed PHMSA's efforts to finalize this important rulemaking based on the consensus built through the Gas Pipeline Advisory Committee ("GPAC") process.[7]

The Associations appreciate PHMSA's efforts to provide guidance through FAQs as operators continue to implement the requirements of the Final Rule. The Associations have used "track changes" below to

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[1] The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 74 million residential, commercial and industrial natural gas customers in the U.S., of which 95 percent — over 71 million customers — receive their gas from AGA members. Today, natural gas meets more than one-fourth of the United States' energy needs.

[2] API is the national trade association representing all facets of the oil and natural gas industry, which supports 9.8 million U.S. jobs and 8 percent of the U.S. economy. API's more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 25 million Americans.

[3] APGA is the national, non-profit association of publicly-owned natural gas distribution systems. APGA was formed in 1961 as a non-profit, non-partisan organization, and currently has over 740 members in 37 states. Overall, there are nearly 1,000 municipally-owned systems in the U.S. serving more than five million customers. Publicly-owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

[4] GPA Midstream Association has served the U.S. energy industry since 1921 and has nearly 70 corporate members that directly employ more than 75,000 employees that are engaged in a wide variety of services that move vital energy products such as natural gas, natural gas liquids ("NGLs"), refined products and crude oil from production areas to markets across the United States, commonly referred to as "midstream activities". The work of our members indirectly creates or impacts an additional 450,000 jobs across the U.S. economy. GPA Midstream members recover more than 90% of the NGLs such as ethane, propane, butane and natural gasoline produced in the United States from more than 400 natural gas processing facilities. In 2017-2019 period, GPA Midstream members spent over $105 billion in capital improvements to serve the country's needs for reliable and affordable energy.

[5] INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 26 members, representing the vast majority of the U.S. interstate natural gas transmission pipeline companies. INGAA's members operate nearly 200,000 miles of pipelines and serve as an indispensable link between natural gas producers and consumers.

[6] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, 84 Fed. Reg. 52,180 (Oct. 1, 2019).

[7] *See* Letter of support from AGA, APGA, API, INGAA, Pipeline Safety Coalition, and Pipeline Safety Trust to Elaine L. Chao, U.S. Secretary of Transportation (Feb. 7, 2019), https://www.ingaa.org/Filings/11520/35822.aspx.

recommend edits to the draft FAQs to improve the clarity, consistency, and usefulness of this guidance. After each FAQ, the Associations have provided comments explaining our proposed edits.

Title: Draft Second Batch of 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 October 1, 2019

Date: November 30, 2020

Summary:

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing supplementary proposed regulatory guidance documents in the form of additional frequently asked questions (FAQs). The first set of FAQs related to this rule were posted to the docket on September 16, 2020. This second batch of FAQs (Batch-2 FAQs) is intended to further help owners and operators of gas pipelines comply with recent revisions to the pipeline safety standards in 49 CFR part 192. These standards 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). Like the first batch of FAQs (Batch-1 FAQs), the draft Batch-2 FAQs will be posted to a PHMSA docket for public comment. PHMSA will consider the comments and subsequently finalize the FAQs. The final Batch-1 FAQs were published on the PHMSA website at https://www.phmsa.dot.gov/guidance.

The Batch-1 FAQs were not deemed "significant" or "otherwise of importance to the Department's interests," as defined by 49 CFR 5.37. Nevertheless, PHMSA voluntarily posted the guidance document draft to the Federal Register for public comment on January 29, 2020, under Docket Number PHMSA-2019-0225. At a public meeting held February 27, 2020, PHMSA provided an overview of the regulation, fielded comments on the draft Batch-1 FAQs, and discussed comments that had been posted to the PHMSA docket.

Attendees at the meeting and others who submitted comments to the docket requested that PHMSA respond to additional questions regarding implementation of the revised part 192 regulations. PHMSA stated it would issue a second batch of FAQs to answer these new questions. Once finalized, these draft Batch-2 FAQs are intended to supplement the Batch-1 FAQs and are 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 comply with the underlying safety standards. The Batch-2 FAQs are intended only to clarify to the public existing requirements under the pipeline safety laws and PHMSA regulations.

General FAQs

FAQ-45. Do the changes made to § 191.23 *Reporting safety-related conditions* impact the conditions under which operators must file Safety-Related Condition Reports (SRCRs)?

No. Revisions made to § 191.23(a)(6) clarify which events should be considered safety-related conditions by operators of distribution or gathering lines, underground natural gas storage facilities, or LNG facilities that contain or process gas or LNG. The Final Rule did not change the types of events described. Section § 191.23(a)(10) was added to clarify the Congressionally-mandated Maximum Allowable Operating Pressure (MAOP) exceedance reporting events considered to be safety-related conditions for transmission pipelines. PHMSA has revised § 191.23 to incorporate this statutory requirement, mandated in Section 23 of the 2011 Pipeline Safety Act, in its regulations.

Associations' Comments: No comments.

FAQ-46. Is the addition of a "covered task" considered a significant modification of an operator's Operator Qualification (OQ) program requiring notification pursuant to § 192.18?

Yes. Section 192.18 applies to notification by the operator of significant changes to their OQ program. Operators who add a new covered task may significantly modify their OQ programs and, if so, must notify PHMSA of these changes, per § 192.805(i).

PHMSA expects operators may add more "covered tasks," or modify existing "covered tasks" to take advantage of the permitted methods to implement the new requirements of the Final Rule safely. For example, an operator may determine that its OQ program needs to incorporate new "covered tasks" in the form of activities (e.g., use of new assessment technologies, testing and verifying material properties, and determining the predicted failure pressure of anomalies) needed to comply with the amended regulations. Insofar as the identification of covered tasks is a key component of any OQ program, the addition of an entirely new "covered task" will often be a significant modification of that program requiring notice pursuant to § 192.18.

Associations' Comments: Adding a covered task is not always a "significant modification" under § 192.805(i). Part 192 does not specify that every new covered task equates to a significant modification. PHMSA should clarify FAQ-46 as recommended above to avoid creating a new regulatory requirement through this FAQ.

Also, the Associations suggest removing the last paragraph of this draft FAQ because it does not provide additional clarity regarding when a modification to a covered task amounts to a significant modification.

FAQ-47. What does PHMSA mean when using the term "piggable segment" in the preamble to the rule?

PHMSA discusses what it considers to be "unpiggable" and "piggable" in the Preamble to 84 FR 52215 (see excerpt below). A pipeline segment is considered unpiggable if it requires major physical modification to accommodate an instrumented ILI tool—such as installing new mainline pipe, permanent launchers or receivers, or valves— or if operational limits—including operating pressure, low flow, pipeline length, or availability of in-line inspection (ILI) tool technology for the pipe diameter—prevent the tool from safely or accurately performing the assessment. On rare occasions, there may be segments that cannot be inspected with an ILI because the line cannot be taken out of service without jeopardizing critical service, as would be the case with power plants; however, those pipelines are still considered piggable and must still be assessed using one of the other methods allowed under § 192.710.

The Preamble to 84 FR 52215 states the following:

PHMSA believes that the term "piggable segment" is very widely understood in the industry and is not including additional definitions or regulatory language to expand upon this term. PHMSA understands that a pipeline segment might be incapable of accommodating an in-line inspection tool for a number of reasons, including but not limited to short radius pipe bends or fittings, valves (reduced port) that would not allow a tool to pass, telescoping line diameters, and a lack of isolation valves for launchers and receivers. Some unpiggable pipelines can be made piggable with modest modifications, but others cannot be made piggable short of pipe replacement.

PHMSA understands that a pipeline segment is piggable if it can accommodate an instrumented ILI tool without the need for major physical or operational modification, other than the normal operational work required by the process of performing the inline inspection. This normal operational work includes segment pigging for internal cleaning, operational pressure and flow adjustments to achieve proper tool velocity, system setup such as valve positioning, installation of temporary launchers and receivers, and usage of proper launcher and receiver length and setup for ILI tools.

In addition, a pipeline segment that is not piggable for a particular threat because of limitations in technology such that an ILI tool is not commercially available, might be piggable for other threats. For example, a pipeline that is unable to accommodate a crack tool might be able to accommodate a conventional MFL or deformation tool, and thus be piggable for those threats. Launcher and receiver lengths are not a reason for a pipeline to be considered unpiggable, since through a minor modification they can be modified to be piggable, and the removal of launchers or receivers from the pipeline segment does not make a pipeline unpiggable either.

Associations' Comments: The Associations recommend additions to the first paragraph above to reemphasize and clarify the preamble language regarding "major physical modifications."

FAQ-48. When establishing the MAOP of Type A and B gathering pipelines, does the operator need to comply with §§ 192.619 and 192.624?

Yes for § 192.619; and no for § 192.624. Operators of Type A and B gathering lines must comply with the requirements of § 192.619 in accordance with § 192.9. For Type B gathering lines, only § 192.619(a), § 192.619(b), and § 192.619(c) apply. Section 192.624 does not apply to Type A or B gathering lines. Section 192.624(a) it applies only to onshore steel transmission pipelines.

Associations' Comments: The Associations recommend additions above to provide further clarity regarding applicability to gathering lines.

FAQ-49. Do any of the new rules apply to distribution lines?

Yes. While the new rules focus primarily on the safety of onshore gas transmission lines, a few new requirements apply to distribution lines as well. Distribution line operators should review the following code sections, revised in the rulemaking to determine if these sections apply to their distribution pipeline systems: §§ 191.23; 191.25; 192.3; 192.5; 192.7; 192.18; 192.517; 192.619; 192.750; and 192.805.

Associations' Comments: No comments.

FAQ-50. Is material verification required for mainline pipeline components other than line pipe?

Yes, but only for some mainline pipeline components. Pursuant to § 192.607(f),material verification for components other than line pipe is required if they are larger than 2 inches in nominal outside diameter or have material grades greater than <u>or</u> equal to 42,000 psi. Section 192.607(f) also requires that any appurtenance regardless of size that are <u>directly installed</u> on the pipeline and <u>cannot be isolated</u> from the mainline pipeline pressure must have its material verified. Section 192.205 outlines the material verification record keeping requirements for pipeline components installed after July 1, 2020, and for those installed on or before July 1, 2020, which only apply to components that are larger than 2 inches in nominal outside diameter <u>and</u> also have material grades greater than <u>or</u> equal to 42,000 psi.

Note that § 192.607 only applies where required by another section of Part 192 (e.g., § 192.624 or § 192.712) and does not apply inboard of station emergency shutdown or isolation valves (see FAQ-37).

Associations' Comments: The Associations recommend additions above to highlight that the scope of § 192.607(f) is not identical to the scope of § 192.205. Also, the Associations recommend an additional paragraph summarizing the scope of § 192.607 for clarity.

FAQ-51. Is the operator required to follow § 192.712(e)(2) when evaluating an anomaly on a steel transmission pipeline with a legacy MAOP (i.e., established according to §192.619(c)) if the operator does not have material properties records and the pipeline is operating at less than 30% SMYS?

It depends. Section 192.712 only applies when referenced by other parts of 192. Because legacy pipelines operating under 30% of SMYS are not subject to MAOP reconfirmation requirements (see § 192.624(a)(2) and FAQ-64), only the following situations could invoke § 192.712(e)(2) for this scenario:

- Evaluating cracking on an HCA segment susceptible to the cyclic fatigue threat [§ 192.917(e)(2)]; and
- Evaluating seam cracking on an HCA segment that has pipe meeting the requirements of § 192.917(e)(4).

Associations' Comments: The Associations disagree with PHMSA's interpretation of § 192.712 applicability in FAQ-51. Section 192.712(a) clearly states that § 192.712 only applies "whenever required by this part," and § 192.712 is currently only referenced in a handful of instances in Part 192—all within the MAOP Reconfirmation (§ 192.624) and HCA threat assessment (§ 192.917) sections of Part 192. However, the MAOP Reconfirmation requirements would not apply to the hypothetical pipeline described in this FAQ.

The Associations anticipate and support that PHMSA will expand the applicability of § 192.712 in the forthcoming "Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendment" final rule

("RIN-2"). However, that broader applicability of § 192.712 is not yet reflected in PHMSA's regulations and should not be implemented through an FAQ. PHMSA should publish RIN-2 as soon as practicable.

FAQ-52. While documenting or verifying material properties and attributes under § 192.607, if an operator determines that the material properties of the pipeline segment are inconsistent with the methods used to establish the current MAOP, would that operator be required to revise the MAOP and report it to PHMSA under §§ 191.23 and 191.25?

It depends. Per § 192.703(a) "No person may operate a pipeline, unless it is maintained in accordance with this subpart [Subpart M – Maintenance]." If the MAOP was established using § 192.619(a), the operator would need to apply § 192.619(a)(1 - 4) to see if an MAOP revision is required. If the current MAOP was established using § 192.619(c) and lower strength materials were found and confirmed to be inconsistent with the method used to establish that MAOP, the operator would then need to apply §§ 192.607, 192.624 (if applicable), and 192.703 for the pipeline segment.

Regardless of how the MAOP is reconfirmed or revised, the operator must also re-evaluate previously assessed anomalies to determine if the defect's predicted failure pressure times the appropriate safety factor is commensurate with the MAOP.

After re-evaluating the MAOP, if necessary, the operator would need to determine whether the reconfirmed MAOP (regardless of location) would trigger a reportable event per §§ 191.23(a)(10) and 191.25(b) as a result of identifying lower material strength than expected, unless the Safety Related Condition report is not required per § 191.23(b). In these situations, PHMSA expects the operator to contact its PHMSA regional office or State program to determine a proper course of action.

Associations' Comments: The Associations recommend a few clarifying edits above. First, FAQ-52 should be edited to clarify that a single anomalous material property reading does not automatically require a change in MAOP if the operator subsequently confirms that the pipe material is actually as expected. Second, PHMSA should remove the references to §§ 192.710 and 192.712 because those sections to not directly address re-evaluation of past anomalies in this scenario. PHMSA should also remove the reference to "class location" safety factor because not all relevant safety factors in Part 192 are directly related to class location. Finally, the FAQ should recognize the SRC reporting exceptions in § 191.23(b).

FAQ-53. If the record retention requirement for welder qualification for steel transmission pipe installed after July 1, 2021, is a minimum of 5 years following construction under § 192.227(c), can an operator use a welder qualification that predates July 1, 2021 to meet the record retention requirement?

Yes. For pipelines installed after July 1, 2021, operators are required to retain welder qualification records for welders actively welding with each qualified procedure. The operator can use a welder qualification record created before July 1, 2021, to demonstrate qualification after that date. If the basis of a welder's qualification is a requalification to a welding procedure for which the welder has been continuously qualified (see §§ 192.229(c) and 192.229(d)), the operator must retain appropriate records demonstrating the individual welder's qualification. At a minimum, these records would include the operator's qualification form and all weld test reports (destructive and nondestructive) to demonstrate continuity of qualification for that welder.

Per § 192.227, records required to demonstrate welder qualification are described in Section 6 of API Standard 1104 (incorporated by reference, see Section § 192.7), or Section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, see Section § 192.7).

Associations' Comments: No comments

Moderate Consequence Area FAQs

FAQ-54. In lieu of performing an MCA study, can an operator designate all non-HCA Class 1 and 2 locations as MCAs?

Yes. Operators may choose to designate all Class 1, 2, 3, and 4 locations outside high consequence areas (HCAs) as moderate consequence areas (MCAs) for determining the applicability of § 192.624(a), but if they do they must apply all MCA-related code requirements to those segments. The operators must update their procedures and records to reflect the designation accordingly.

Associations' Comments: No comments

FAQ-55. Which is the appropriate designation for a pipeline segment identified as being located in an HCA per § 192.903 as well as in an MCA per § 192.3??

A pipeline cannot meet the definition of both an HCA and an MCA. The definition of an MCA includes the statement "and that does not meet the definition of high consequence area, as defined in §192.903" An operator may elect to categorize MCAs, Class 1, 2, 3, or 4 locations as HCAs and update its procedures and records accordingly.

Associations' Comments: The Associations recommend corrections to the code references above. Additionally, the Associations recommend referencing the language of the MCA definition in 192.3, which explicitly excludes segments that meet the HCA definition.

Spike Hydrostatic Testing FAQs

FAQ-56. When is a spike test required? What code sections require a spike test?

Spike hydrostatic pressure testing described in § 192.506 may be required based on multiple Part 192 sections to properly assess threats applicable to the pipeline. There are multiple acceptable assessment methods for any specific threat, as described in those code sections. (See §§ 192.710(c)(3), 192.921(a)(3) and 192.937(c)(3).)

Associations' Comments: The Associations recommend clarifying edits above to acknowledge that spike testing is not the only assessment method allowed under Part 192 for cracking.

Material Verification FAQs

FAQ-57. If an operator conducts an anomaly direct examination on a steel transmission pipeline and no pipe is required to be removed from service, must the operator perform a cutout for material properties testing under § 192.607(c)?

No. In this case, the operator is not required to perform a cutout for material property testing unless required by the operator's procedures. Section 192.607(c) requires operators to develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments during each listed activity. Per § 192.607, and clarified in FAQ-24, 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. In-situ nondestructive testing equipment must be calibrated in accordance with the manufacturer's recommendations prior to performing the test per § 192.607(d)(3).

Per § 192.712(e), operators must use pipe and material properties documented in traceable, verifiable, and complete (TVC) records in their analysis of predicted failure pressure and remaining life of anomalies. If documentation required for the analyses is not available, the operator must obtain the undocumented data through § 192.607. Until documented material properties are available, operators must use the conservative values included in § 192.712(e)(2).

Associations' Comments: The Associations recommend clarifying edits above to reflect that nondestructive testing may be used to verify properties other than material strength. Also, the Associations believe that testing equipment should be calibrated in accordance with the manufacturer's recommendations, which could be completed by the operator or the equipment provider.

FAQ-58. How many sample locations are required to verify material properties and attributes per § 192.607(e) if an operator has a 10-mile long pipeline segment with similar but unknown material attributes, and two miles of the segment contain HCAs or Class 3 or 4 locations? May samples from non-HCA or Class 1 or 2 locations be used in assessing the material properties of HCA or Class 3 or Class 4 locations?

Two sampling locations are required for this scenario. The HCAs, Class 3, or Class 4 within this two-mile segment need not be contiguous.

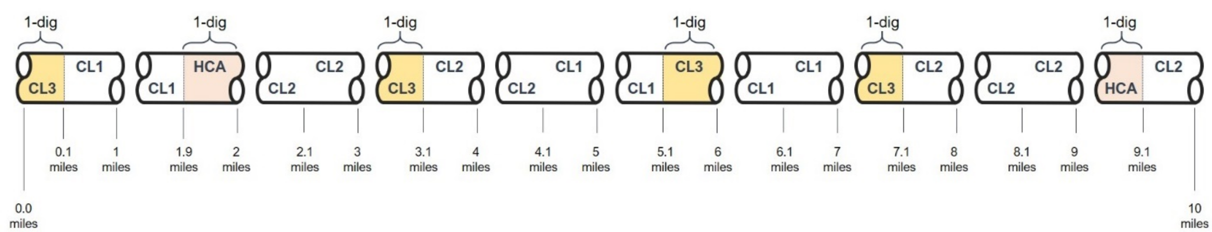
PHMSA expects operators to opportunistically perform sampling to obtain representative samples of the pipe population at excavations that expose the pipe as required by § 192.607(e)(2). The "one excavation per mile" requirement of §192.607(e)(2) applies to the quantity of samples, not the required spacing between samples. Samples should be taken at excavations within a uniform population until the required quantity is reached, regardless of the distance between those samples within the population, as required by §192.607(e)(2). If the length of the applicable segments is greater than two miles, such as 2.1 miles, the required number of excavations would be three because the regulation requires rounding up to the nearest whole number per §192.607(e)(i).

Furthermore, operators may, for the purposes of material properties verification required for an HCA, MCA, Class 3, or Class 4 pipeline segment pursuant to § 192.624(a), rely on material sampling from a non-HCA, Class 1, or Class 2 pipeline segment (which segment would not otherwise need material verification per § 192.607(a)). By way of example, an operator may rely on material sampling from a Class 1 pipeline segment within readily-accessible farmland for verification of the material properties of a pipeline segment that is part of the same pipe population but within a Class 3 housing development. However, if operators had information (e.g., collected from previous excavations or ILI surveys) that the material of that non-HCA, Class 1, or Class 2 pipeline segment did not have similar material properties and attributes (e.g., nominal wall thickness, grade, etc.) to the HCA, Class 3, or Class 4 pipeline segment, then § 192.607(e)(1) would prohibit reliance on material samples from that dissimilar pipe.

Associations' Comments: The Associations have significant concerns with proposed FAQ-58. As drafted, it appears to change the requirements of § 192.607(e). Section 192.607(e) defines a *quantity* of excavations that an operator must use to *opportunistically* verify material properties. Operators cannot control the spacing between opportunistic excavations because these excavations are driven by anomaly evaluations and other maintenance requirements.

Furthermore, the language in §192.607(e) is clearly referencing the number of excavations required as a function of the cumulative mileage associated with any single population and does not specify a minimum or maximum spacing between excavations within the same population. As stated under § 192.607(e), "…The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous." If the maximum spacing between excavations for a single population were one mile, § 192.607(e)(2)(ii) would not make sense because more than 150 excavations would always be required for a population of 150 miles, unless the entire 150-mile population was continuous, but § 192.607(e)(1) clearly states that the pipeline segments within a single population need not be continuous.

This change could greatly increase the number of material verification excavations required to comply with § 192.607(e). Below is an example: a single, cumulative population of 0.6 miles would only require one dig to satisfy a one per mile of population requirement; however, under FAQ 58, this same sampling would require six digs with the requirement that the eligible segments be separated at one mile or less of one another.



Only HCA and Class 3 segments applicable under 192.607

All applicable segments are associated with a single population

0.6 Total Miles of Non-Contiguous Segments in the Population

- **192.607(e)(2) Sampling: One sample / mile of population = *ONE Sample***
- **FAQ #58: Digs must be within 1-mile of one another = *Six Samples***

Segment	Length (miles)	Class	Separation between Segments
1	0.1	CL3	0
2	0.1	HCA	1.8
3	0.1	CL3	1
4	0.1	CL3	2
5	0.1	CL3	1
6	0.1	HCA	1.9
Total	0.6 Miles		

The Associations have recommended edits above to address these concerns. Additionally, the Associations recommend deleting the final proposed paragraph because the requirements for material verification for in-scope MCA pipe should not differ from the requirements for HCA, class 3, and class 4 pipe.

FAQ-59. What is the sampling frequency for components requiring verification of material properties described under § 192.607(f)?

The regulation does not specify a sampling frequency for components. However, PHMSA expects operators, pursuant to § 192.607(f) to verify material properties by opportunistically sampling components at the same frequency as line pipe per § 192.607(e).

As outlined in § 192.607(f), operators must verify material properties of components per § 192.607(c). To do so, operators must establish and document the ANSI rating or pressure rating (per ASME/ANSI B16.5 (incorporated by reference, see § 192.7)). However, operators are not required to verify pressure ratings or otherwise test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline. Consistent with FAQ-37, the boundary of compressor, meter, and pressure-limiting stations for MAOP reconfirmation and material verification purposes begins at the station emergency shutdown or isolation valves. Operators may also exercise the alternative sampling program allowance described in § 192.607(e)(5) to verify the material properties of components.

Associations' Comments: The Associations do not agree that § 192.607(f) requires material verification of every in-scope component that is above-ground. Although § 192.607(f) does not define a sampling frequency, Section 192.607 has always been premised on the concept of opportunistic sampling to build confidence in the properties of a population. For both above-ground and below-ground components, operators should be required to implement a sampling plan that aligns with § 192.607(e). Otherwise, this FAQ could be interpreted to require operators to verify the pressure rating of all in-scope above-ground components immediately, which would be inconsistent with the opportunistic nature of § 192.607. Additionally, sampling frequency is defined in § 192.607(e), not § 192.607(c). The Associations have recommended edits above.

Also, the Associations have recommended clarifying edits to help ensure clarity that § 192.607 is not intended to apply inside stations and similar facilities (within the boundaries of the emergency shutdown/isolation valves). The Associations recommend that FAQ-59 cross-reference FAQ-37, which establishes similar limits for the MAOP reconfirmation requirements inside stations, since MAOP reconfirmation will often be the trigger for material verification requirements.

To provide additional clarity regarding the applicability of MAOP reconfirmation (§ 192.624) and material verification (§ 192.607) requirements, the Associations also recommend that PHMSA produce suggested applicability drawings that align with FAQ-37 and FAQ-59.

FAQ-60. If an operator of a pipeline segment does not have documented traceable, verifiable, and complete (TVC) material properties records for yield strength, and used 24,000 psig (pursuant to §§ 192.619(a) and 192.107(b)(2)) to determine its MAOP, must the operator still perform material properties testing for yield strength in accordance with § 192.607(f)?

No. PHMSA considers pipeline segments that have an established and documented MAOP using 24,000 psig for the yield strength (per § 192.107(b)(2)) to have a TVC material property record for yield strength. This approach of using a 24,000 psig yield strength will result in a conservative value for MAOP determination.

If that same pipeline segment requires MAOP reconfirmation and a pressure test is to be performed, PHMSA would not expect the operator to perform material properties testing for yield strength at the pressure test manifold sites when 24,000 psig yield strength values are being used for MAOP determination. For that segment, the yield strength record is considered to be TVC based on the conservative assumption that the operator applied in establishing the MAOP. An operator is encouraged, but not required, to test for yield strength, pipe wall thickness, and seam type at these locations per § 192.607 requirements. Additionally, if the same pipeline segment has an anomaly that requires evaluation per § 192.712 requirements, the operator must use the conservative assumptions described in § 192.712(e)(2) for determining predicted failure pressure and remaining life.

Associations' Comments: None.

FAQ-61. If an operator does not have records of the tests, inspections, and attributes required by the manufacturing specifications for chemical composition for a steel transmission pipeline segment installed on or before July 1, 2020, must an operator perform testing to determine the chemical composition per §§ 192.67 and 192.205?

No. Per §§ 192.67 and 192.205, operators must make and retain chemical composition records for pipelines installed after July 1, 2020, and retain chemical composition records, if the operator already has them, for pipelines installed on or before July 1, 2020.

Furthermore, an operator is required to verify the material properties, per § 192.607, for those material properties needed to comply with the requirements of Part 192 where such records are not TVC.

Chemical composition records are not required to establish the MAOP of a pipeline, but pursuant to § 192.225, information regarding chemical composition may be needed to qualify a welding procedure.

Associations' Comments: The Associations recommend edits to clarify that chemistry data is not always needed to qualify a welding procedure and to clarify that there is no code requirement to have TVC chemistry data in order to have a qualified welding procedure. Many existing welding procedures were qualified before PHMSA created the TVC standard.

Maximum Allowable Operating Pressure Establishment and Reconfirmation FAQs

FAQ-62. Does an operator need to collect ultimate tensile strength records under either §§ 192.607 or 192.712 when the operator already has TVC records demonstrating the grade or minimum yield strength of the pipeline segment?

It depends. An operator does not need to collect ultimate tensile strength records of materials for determining the MAOP if the operator already has TVC records demonstrating the grade of the pipe. If an operator does not have TVC records demonstrating the grade, the operator must conduct future testing for both minimum yield strength and ultimate tensile strength per § 192.607(c)(1) and (2).

An operator may, however, need ultimate tensile strength values to accurately predict a failure pressure for some type of anomalies depending on the analysis method used. The analyses performed per § 192.712 must use pipe and material properties that are documented in TVC records. If documented data required for any analysis is not available, an operator must follow § 192.607 to obtain the undocumented data and use conservative values as prescribed in § 192.712(e)(2) until documented material properties are available. In the case of ultimate tensile strength, an operator must follow § 192.712(e)(2)(iii), which could include using the ultimate tensile strength values as defined in API 5L for the known or assumed pipe grade.

Associations' Comments: The Associations recommend removing the first reference to § 192.607(b) and (c) because these subsections do not describe what a TVC record is, rather they provide a method to verify material properties *if a TVC record does not already exist*. The Associations also recommend adding clarity to the last sentence of the FAQ to elaborate on how § 192.712(e)(2)(iii) could be applied to ultimate tensile strength.

FAQ-63. Does an operator need more than one record of a material property or attribute to demonstrate the documentation is TVC per § 192.607?

It depends. Records vary greatly in the amount of information documented. Some operators may need to include multiple corroborating documents to constitute a TVC record, while others may have that TVC record in a single consolidated document. A single document such as a pipe manufacturer's "mill test report" with the required pipe mechanical and chemical properties would still need some identifying number or description linking the material attributes to the pipeline that was placed into service (e.g., work order, line designation).

Associations' Comments: The Associations recommend removing the reference to § 192.607(b). Section 192.607(b) defines recordkeeping requirements for any material properties verified under § 192.607. It does not establish a list of material attributes needed to create a TVC record—records necessary to meet different requirements of Part 192 will inherently contain different attributes. As noted in this FAQ, operators are not required to have one single record that covers all pipeline attributes.

FAQ-64. Is a pipeline segment with an MAOP established under § 192.619(c) (i.e. "legacy" MAOP) also required to comply with § 192.624(a)(1)?

No. A pipeline segment with an MAOP established under § 192.619(c) is applicable under § 192.624(a)(2), therefore it is not subject to § 192.624(a)(1). Section 192.624(a)(2) still requires the implementation of the additional paragraphs in § 192.624(b) through (d).

Pipeline segments with an MAOP established under § 192.619(c) must comply with § 192.624(a)(2) if the MAOP is greater than or equal to 30% SMYS and is located in an HCA, Class 3 or 4 location, or a moderate consequence area if the segment can accommodate inline inspection tools. Non-legacy pipelines where the MAOP was established per § 192.619(a) are subject to the applicability of § 192.624(a)(1) if they do not have the TVC records required by the hydrotest records of § 192.517 and they are located in an HCA or a Class 3 or 4 area.

Associations' Comments: None.

FAQ-65. Does § 192.624(a)(2) require operators to re-perform MAOP reconfirmation for legacy pipelines that have already been pressure tested in accordance with § 192.619(a)(2)?

No. Section 192.624(a)(2) does not require MAOP reconfirmation if the operator has the documents to confirm a pressure test per §§ 192.517(a), regardless of when it was conducted. Although a TVC record of a pressure test conducted prior to July 1, 2020 is sufficient to meet MAOP reconfirmation requirements, the operator may still be required to verify material properties in accordance with §192.607 to meet other requirements of Part 192, such as §192.712.

Regardless of whether a pressure test has been conducted, an operator must retain records of the 5-year operating history (1965–1970) in order to operate a pipeline under § 192.619(c) (e.g., if the pipeline has a legacy MAOP above 72% of SMYS).

Associations' Comments: The Associations are concerned that FAQ-65 as drafted may create confusion regarding the distinction between MAOP reconfirmation and material verification requirements. During the Gas Pipeline Advisory Committee (GPAC) meetings to discuss this rulemaking, PHMSA emphasized that "a pipe segment with a past pressure test meeting subpart J in accordance with 192.619(a)(2) and with TVC records that demonstrate compliance with 192.619(a)(2), would not require MAOP Reconfirmation under 192.624(a)."[8]

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[8] GPAC Meeting Slides at 19 (Mar. 26-28, 2018), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=942. When presenting § 192.624(a) to the GPAC, a PHMSA representative confirmed that "a pipe segment with a pressure test

But the language in the current draft FAQ could be read to imply that a TVC pressure test record is not enough to avoid MAOP reconfirmation requirements for legacy pipelines, and that both a record of the 1965–1970 operating history and TVC materials records are also required. The Associations recommend clarifying language above to separate these distinct requirements. Although § 192.624(c)(1)(iii) requires operators to use future MAOP reconfirmation pressure tests as an opportunity to take material property samples, it is impossible for an operator to do this for pressure tests that occurred prior to the final rule.

Also, when discussing pressure test record requirements under § 192.624(a), the Associations recommend only cross-referencing § 192.517(a) because that is the subsection of Subpart J referenced in § 192.624(a). Section 192.624(a) does not reference §§ 192.503 or 192.505.

Assessments Outside of High Consequence Areas FAQs

FAQ-66. Can an operator's "risk-based prioritization" of initial assessments required by § 192.710(b)(1) allow a pipeline segment containing a lower-risk MCA to be assessed prior to a higher-risk MCA in another pipeline segment?

Yes. PHMSA requires operators to perform their initial assessments per § 192.710 based on a "risk-based prioritization" schedule. This requirement does not prevent an operator from considering other non-risk factors that may influence the schedule of assessments (e.g., ILI availability). Operators must have and follow written procedures per § 192.605(a) and retain records per § 192.603(b) to document the rationale for their assessment schedule and any deviations to that schedule that may be necessary in the future.

Associations' Comments: None.

FAQ-67. Can an operator use External Corrosion Direct Assessment (ECDA) as a direct assessment method to assess threat of third-party damage per § 192.710(c)?

Yes. While third-party damage was not explicitly listed in § 192.710(c)(6), ECDA may be used as a direct assessment method to address the threat of third-party damage for assessments outside of high consequence areas, similar to HCA assessments conducted per Subpart O. As stated in § 192.710(c)(6), the ECDA assessment must be conducted in accordance with §§ 192.923; 192.925; 192.927; and 192.929.

Associations' Comments: None.

FAQ-68. Does the statement in § 192.712(b) "or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result" allow operators to use corrosion evaluation methods for anomaly evaluations that give predicted failure pressures less than either R-STRENG or ASME/ANSI B31G?

Yes. Section § 192.712(b) allows the use of alternative evaluation methods that results in an equivalent level of safety as either R-STRENG or ASME/ANSI B31G. In determining whether an alternative method will results in an equivalent level of safety, the operator should evaluate both the accuracy and precision of the alternative model relative to R-STRENG or ASME/ANSI B31G.
Associations' Comments: The Associations believe that "an alternative equivalent method of remaining strength calculation that will provide an equally conservative result" should be interpreted as allowing

meeting subpart J in accordance with Section 619(a)(2), and with the TVC records that demonstrate compliance with Section 619(a)(2) would not require MAOP reconfirmation under new Section 624(a)." GPAC Meeting Tr. 95:1-7 (Mar. 26, 2018), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=970.

alternative methods that result in an equal level of safety. This requirement should not be interpreted as requiring every calculation method to produce the same predicted failure pressure—if that were the requirement, the allowance of alternative calculation methods would be pointless.

The level of safety achieved from a model is based on how effectively the model predicts reality. This is achieved by considering the accuracy and precision of the model. The accuracy (or bias) of a model measures how the average prediction differs from the actual value. The precision (or scatter) of a model is the measures the variability of the predictions.

ASME/ANSI B31G and R-STRENG models were developed based on differing assumptions that represent differing levels of accuracy and precision. The average PFPs for R-STRENG and ASME/ANSI B31G are higher than the actual burst pressure. Thus, these methods provide safe decisions in general. That said, the average PFPs from R-STRENG are higher than the PFPs from ASME/ANSI B31G methods. However, the scatter is much lower for RSTRENG model (i.e. higher precision) compared to ASME/ANSI B31G model because it represents the actual corrosion area more precisely. Despite predicting lower PFPs, R-STRENG provides an equivalent or higher level of safety due to its higher precision compared to ASME/ANSI B31G model. So ASME/ANSI B31G model and R-STRENG themselves do not produce the same PFP calculation but provide equivalent safety.

Any alternative model for remaining strength calculation would also have differing level of accuracy and precision. Ideally, any model that represents an improvement over R-STRENG or ASME/ASNI B31G method would have a higher level of accuracy and precision. However, a model with higher level of accuracy and precision, at the same level of safety, would predict higher failure pressures compared to R-STRENG or ASME/ASNI B31G method. Yet PHMSA's proposed FAQ-68 appears to prohibit the use of an alternative model that would result in higher accuracy and precision compared to R-STRENG and ASME/ANSI B31G models. The Associations believe this is not PHMSA's intent and recommend PHMSA clarify FAQ-68 to focus on an equal level of safety from alternative models, not equal (or lower) predicted failure pressures.

PHMSA's proposed FAQ-68 will hinder development of new and innovative remaining strength prediction models. R-STRENG and ASME/ANSI B31G models were developed over 30 years ago and they have limitations, like any calculation methods. Not allowing the use of more accurate and precise alternative models limits operators' ability to promote a more safe and reliable pipeline system.