<u>Title</u>: 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

<u>Date</u>: Wednesday, April 19, 2023

<u>Summary</u>:

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing supplementary 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 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) (Final Rule). Using a similar review process as the first batch of FAQs (Batch-1 FAQs), the draft Batch-2 FAQs were posted to a PHMSA docket for public comment on December 21, 2020. PHMSA considered the comments received by March 16, 2021 along with the results of recent "pilot" inspections of pipeline operators to finalize the Batch-2 FAQs. Both Batch-1 and Batch-2 FAQs are published on the PHMSA website at https://www.phmsa.dot.gov/guidance. 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.

PHMSA provides FAQs to help the public understand how to comply with the existing requirements under the regulations. FAQs are not substantive rules, are not meant to bind the public in any way, and do not assign duties, create legally enforceable rights, or impose new obligations not otherwise contained in the existing regulations. However, an operator who can demonstrate compliance with the FAQs is likely to be able to demonstrate compliance with the relevant regulations.

<u>General FAQs</u>

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 which Maximum Allowable Operating Pressure (MAOP) exceedance reporting events are safety-related conditions for transmission pipelines. PHMSA revised § 191.23 to incorporate the statutory requirement, mandated in Section 23 of the 2011 Pipeline Safety Act, into its regulations.

Operators are reminded that § 191.7(c) requires that they concurrently report safety-related conditions, including MAOP exceedances, to the appropriate State agency for intrastate pipeline transportation or when the State agency acts as an agent of the Secretary with respect to interstate transmission facilities.

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?

It depends. Section 192.805(i) applies to notification by the operator of significant changes to their OQ program. Operators who add new covered task(s) or alter existing covered tasks may be significantly modifying their OQ programs and, if so, must notify PHMSA of these changes, per § 192.805(i) and in accordance with § 192.18. Operators should define in their OQ program criteria for evaluating whether new or modified "covered tasks" are considered to be a significant modification of their OQ plans which in turn would warrant notification to PHMSA per § 192.18.

PHMSA expects operators to add more "covered tasks," or modify existing "covered tasks" to take advantage of the permitted methods to safely implement the new requirements of the Final Rule. 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" may be a significant modification of that program requiring notice pursuant to § 192.18.

Furthermore, an operator's efforts to comply with new regulations may require modification of an existing "covered task" within its OQ program to revise or elaborate on sub-processes (e.g., supporting activities such as excavation, coating removal, recoating, backfilling, removing previous repairs, removing casings to determine the properties of the carrier pipe, etc.) integral to that existing "covered task."

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 the Final Rule (see excerpt below). A pipeline segment constructed after April 1994 was required to be designed to accommodate an ILI tool (and therefore would be considered piggable) per § 192.150. A pre-1994 pipeline is considered unpiggable if it requires major physical modification to accommodate an instrumented ILI tool 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. If a segment is not able to accommodate any commercially-available tool for a particular threat to which the segment is susceptible, the segment must still be inspected per § 192.710 for the threats for which the segment can accommodate an appropriate in-line inspection tool or use other assessment methods.

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 the Final Rule 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. 84 FR 52180, 52215 (October 1, 2019).

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

Yes. Operators of Type A, Type B, and certain Type C gathering lines must comply with the requirements of § 192.619 in accordance with § 192.9. Type A gathering lines are subject to all requirements of § 192.619 except for § 192.619(e). For Type B gathering lines, § 192.619(a), § 192.619(b), and § 192.619(c) apply. Type C gathering lines with outside diameter greater than 12.75 inches are subject to § 192.619(a) or § 192.619(c), and the remaining Type C gathering lines are not necessarily required to establish MAOP pursuant to § 192.619.

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, which were 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.

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)(2), material verification for components other than line pipe is required if they are larger than 2 inches in nominal outside diameter or have material yield strength grades of 42,000 psi or greater. Section 192.607(f) also requires that any appurtenance regardless of size that is <u>directly installed</u> on the pipeline and <u>cannot be isolated</u> from the mainline pipeline pressure must have its material verified. Note that § 192.607(a) provides that the material verification requirement only applies where required by another section of part 192 (e.g., §§ 192.619(a)(4), 192.624(c), 192.632(a), or 192.712) and does not apply inboard of station emergency shutdown or isolation valves (see FAQ-37).

Section 192.205 outlines the material verification record keeping requirements for pipeline components. For pipeline components installed on or before July 1, 2020, if operators have records documenting the manufacturing standard and pressure rating for components that are larger than 2 inches in nominal outside diameter having material yield strength grades of 42,000 psi or greater, these records must be retained per § 192.205(a). Section 192.205(b) also requires operators to collect or make, and retain for the operational life of the component, records documenting the manufacturing standard and pressure rating for any such components installed after July 1, 2020.

FAQ-51. Is the operator required to follow § 192.712 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 required by other provisions of part 192. Because legacy pipelines operating under 30% of SMYS are not subject to MAOP reconfirmation requirements (see § 192.624(a)(2) and FAQ-64), the following situations could invoke § 192.712 for this scenario:

- Calculating remaining wall thickness for each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP as required by § 192.485(c) (Effective May 24, 2023);
- Remediating conditions discovered during assessments conducted under § 192.710 that could adversely affect the safe operation of a pipeline, as required by § 192.710(f);
- Evaluating cracking on an HCA segment susceptible to the cyclic fatigue threat as required by § 192.917(e)(2); and
- Evaluating seam cracking on an HCA segment that has pipe meeting the requirements of § 192.917(e)(4).

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. 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 using the newly confirmed material properties. Per §§ 192.619(a)(4), 192.710(g) and 192.712, the operator must determine if the defect's predicted failure pressure times the appropriate safety factor is still 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). The operator may contact its PHMSA regional office or State program to discuss a proper course of action.

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 by § 192.227 to retain welder qualification records for welders who performed or are in the process of performing welds on a regulated pipeline pursuant to a qualified welding 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 in accordance with § 192.227. 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 § 192.7), or Section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, see § 192.7).

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, per § 192.624(a)(2)(iii) they must reconfirm MAOP under § 192.624 for any piggable pipeline segments in locations designated as MCAs where the segment's MAOP was established in accordance with § 192.619(c), and per § 192.710 they must also conduct integrity assessments in locations designated as MCAs. The operators must update their procedures and records to reflect the designation accordingly per § 192.624(b).

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, since an MCA is an area "that does not meet the definition of high consequence area, as defined in §192.903" (per § 192.3). An operator may elect to categorize MCAs or other non-HCA locations as HCAs and update its procedures and records accordingly.

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 applied 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).)

<u>Material Verification FAQs</u>

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. Operators must ensure that *in situ* nondestructive testing equipment is calibrated with a known strength of material and 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).

FAQ-58. A) 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 – either continuous or in discrete sections - of the segment contain HCAs or Class 3 or 4 locations?

A minimum of two sampling locations are required for this scenario because § 192.607(e)(2) requires one excavation per mile (rounded up to the nearest whole number) for each population of similar pipe segments defined according to § 192.607(e)(1). However, per § 192.607(e)(1), the operator would still need to provide evidence that the pipe material properties and attributes were similar in each of the HCA, Class 3, and Class 4 areas (i.e., they were of the same population group and same pipe vintage as defined in § 192.607(e)). The HCAs, Class 3, or Class 4 pipe populations within this two-mile segment need not be contiguous.

PHMSA expects operators to opportunistically perform sampling to obtain representative samples of the pipe population group 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 <u>and</u> spacing of samples along the pipeline. Per § 192.607(e), samples must be taken at excavations within a similar population of material properties and attributes until the required sample quantity prescribed by regulation to verify material properties and attributes of that population group is reached. PHMSA will not consider attribute sampling from the same joint of pipe to be representative of the entire pipe population group. Sampling must also occur within each cumulative 1-mile segment of the pipeline with a similar population of material properties and attributes as required by §192.607(e)(2). If the length of the applicable segments is greater than one mile but less than two miles, such as 1.2 miles, the required number of excavations would still be two because the regulation requires rounding up to the nearest whole number (per §192.607(e)(2)(i)) to determine the minimum number of excavations.

B) 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?

For the purposes of material property verification for an HCA, MCA, Class 3, or Class 4 pipeline segment (covered segment), operators may rely on material sampling from a pipeline segment not requiring material property verification. However, to utilize this option, per § 192.607(e), operators must prove that materials from a "non-covered" segment are from the same population group as the covered segment. To demonstrate that the segments are from the same population group, per § 192.607(e), operators must have records showing that the non-covered segment has similar material attributes (e.g., collected from previous excavations or ILI surveys) as the covered segment. The pipe attribute samples from the non-covered pipeline segments should be taken as close as logistically practicable to the pipe segments needing MAOP reconfirmation.

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

Section 192.607(f) does not specify a sampling frequency for components. However, operators are required by § 192.607(c) and (f), to verify material properties opportunistically. The preferred way to meet this requirement would be by 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, compressor, meter, and pressure-limiting station emergency shutdown and isolation valves are subject to MAOP reconfirmation and material verification requirements. Operators may also exercise the alternative sampling program allowance described in § 192.607(e)(5) to verify the material properties of components.

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.

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.

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?

If the operator already has TVC records demonstrating the grade of the pipe per §§ 192.607(b) and (c), 192.67 or 192.205, an operator does not need to collect ultimate tensile strength records of materials for determining or reconfirming the MAOP. 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 types 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 an assumed yield strength (see §§ 192.107(b)(2), 192.607 (g) and 192.712(e)) for the pipe grade and using API 5L to determine the ultimate tensile strength for the pipe grade.

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 and types 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. In any event, the material property records must contain the attributes in § 192.607(b), 192.67, or 192.205. 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).

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) falls under § 192.624(a)(2), and 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 TVC records necessary to establish the MAOP, including hydrotest records required by § 192.517, and they are located in an HCA or a Class 3 or 4 area.

FAQ-65. RESERVED

<u>Assessments Outside of High Consequence Areas FAQs</u>

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, segment continuity). 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.

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 is 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.

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?

Section 192.712(b) allows the use of alternative evaluation methods that result in a level of safety for the anomaly's predicted failure pressure (PFP) that is equivalent to either R-STRENG or ASME/ANSI B31G. In determining whether an alternative method will result 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. The alternative equivalent method of a remaining strength calculation must provide an equally conservative result. The operator can demonstrate the alternative method is equivalent through a comparison of its predicted failure pressures to R-STRENG or ASME/ANSI B31G, burst pressure tests used to support the comparison, and any other technical reviews used to qualify the alternative method for varying corrosion profiles.

The level of safety achieved from an alternate evaluation method must be based on how effectively the model predicts the actual safety performance of the anomaly being evaluated in accordance with § 192.712(b). This is achieved by considering the accuracy and precision of the model, and is supported by empirical data using similar pipe materials, anomaly characteristics, and operating pressures and through destructive tests to validate the model.

FAQ – 69. RESERVED