

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

Pipeline Safety: Safety of Gas Transmission  
Pipelines, MAOP Reconfirmation, Expansion of  
Assessment Requirements and Other Related  
Amendments

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**COMMENTS ON PIPELINE SAFETY: SAFETY OF GAS TRANSMISSION PIPELINES, MAOP  
RECONFIRMATION, EXPANSION OF ASSESSMENT REQUIREMENTS AND OTHER RELATED  
AMENDMENTS**

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## I. Introduction

The American Gas Association (AGA)<sup>1</sup>, American Petroleum Institute (API)<sup>2</sup>, American Public Gas Association (APGA)<sup>3</sup> and Interstate Natural Gas Association of America (INGAA)<sup>4</sup> (jointly “the Associations”) submit these comments for consideration by the Pipeline and Hazardous Materials Safety Administration (PHMSA) concerning the “Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments” rule (“transmission mandates rule”). On March 26, 2018, PHMSA announced that this would be the first of two rules<sup>5</sup> addressing the gas transmission pipeline topics raised in the 2016 “Safety of Gas Transmission and Gathering Lines” Notice of Proposed Rulemaking (NPRM)<sup>6</sup>, and that this rule would address gas transmission pipeline mandates from the 2011 Pipeline Safety Act. The Associations plan to submit a second, separate set of comments to address the topics that PHMSA announced it will include in its second gas transmission rule, the “Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments” rule. PHMSA also announced that it would address its proposals pertaining to gathering lines in a separate, dedicated Gas Pipeline Advisory Committee (GPAC) meeting and final rule.

The gas transmission rules were discussed during a series of five GPAC meetings in 2017 and 2018.<sup>7</sup> The GPAC meetings provided the GPAC Members, PHMSA representatives, the regulated community, and the public the opportunity to discuss topics contained within the transmission rules. The Associations

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<sup>1</sup> 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 73 million residential, commercial and industrial natural gas customers in the U.S., of which 95 percent — over 69 million customers — receive their gas from AGA members. Today, natural gas meets more than one-fourth of the United States' energy needs.

<sup>2</sup> 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.

<sup>3</sup> 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 700 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.

<sup>4</sup> The Interstate Natural Gas Association of America (INGAA) is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 27 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.

<sup>5</sup> See “Gas Rule Split-Out” presentation from Mr. Alan Mayberry, Associate Administrator for Pipeline Safety (March 26, 2018). <https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=967>.

<sup>6</sup> Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 29830 (May 13, 2016).

<sup>7</sup> Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 82 Fed. Reg. 51760 (November 7, 2017). The GPAC is a peer review committee charged with providing recommendations on the technical feasibility, reasonableness, cost-effectiveness, and practicability of PHMSA's proposed safety standards for gas pipeline facilities. 49 U.S.C. §§ 60102(b)(2)(G), 60115.

provided PHMSA and the GPAC members with comments following the first four GPAC meetings that were intended to summarize the views expressed during the meetings and elaborate on the concerns identified. These comments included markups to the proposed regulatory text that were intended to mirror the votes and discussions held by the GPAC and also identified outstanding concerns. The proceeding comments are similar in content and structure. The Associations hope that these comments will assist PHMSA as it drafts a final rule that advances pipeline safety.

## II. General Comments

### A. Definitions of Transmission Line & Distribution Center

The Associations suggest that two of the most critical proposals within the NPRM are the modifications to the definition of a *Transmission line* and the incorporation of a definition for *Distribution center*. Clarity surrounding both definitions is necessary for two primary reasons:

- PHMSA's current and proposed definition of *Transmission line* references *Distribution center*. Without resolving the long-standing ambiguity surrounding the definition of *Distribution center*, the Associations assert that PHMSA will not be able to accurately or fully calculate the burdens associated with the final rules.
- Operators must understand the population of pipelines impacted by the final rules, which requires definitions for both *Transmission line* and its referenced *Distribution center*. If there is uncertainty after the transmission mandates final rule is published, operators will be left trying to discern if a pipeline falls within the scope of the new requirements.

PHMSA has proposed four significant modifications to the definition of *Transmission line*:

- (1) The codification of a definition for *Distribution center*.
- (2) The addition of a fourth criterion, "is voluntarily determined by the operator to be a transmission pipeline."
- (3) A change of "operates at a hoop stress" to "has an MAOP" of 20% percent or more of Specified Minimum Yield Strength (SMYS) for the transmission line designation.
- (4) The addition of the clause "or a connected series of pipelines."

The Associations provide the following comments on each of these modifications.

#### (1) The codification of a definition for Distribution center.

The Associations strongly believe it is critical that PHMSA codify a definition for *Distribution center* in the transmission mandates final rule. There have been countless formal and informal requests for interpretations regarding the definition of *Distribution center*. Understandably, there is substantial variance in how this section of the *Transmission line* definition is currently being interpreted. The Associations believe that the codification of a definition for *Distribution center* will serve to better align all stakeholders on which pipelines are distribution versus transmission.

In the NPRM, PHMSA proposed the following definition for *Distribution center*.

*Distribution center* means a location where gas volumes are either metered or have pressure or volume reductions prior to delivery to customers through a distribution line.

While the Associations offer a different definition, PHMSA's proposed definition is a step in the right direction. The Associations believe that modifications to the proposed definition would provide a clear and consistent understanding, interpretation, and application of *Distribution center*. The Associations

offer the following changes, which were discussed during the March 2018 GPAC meeting and appeared to receive wide support:

- A *Distribution center* begins at the initial point where gas enters piping that is used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale. PHMSA's proposed definition, "where gas volumes are either metered or have pressure or volume reductions," may create confusion, as local distribution companies generally have multiple regulator stations and pressure reductions between the initial entry point from the transmission line and final delivery to their customers.
- A reduction in volume of gas would include a lateral off the main *Transmission line*.
- The final phrase in PHMSA's proposed definition, "through a distribution line," is unnecessary and could lead to confusion. The Associations encourage PHMSA not to reference a *Distribution line* in the definition for *Distribution center* as it creates a circular reference between the definitions. Additionally, this phrase could be interpreted to mean that all downstream piping must be classified as "distribution" in order for a *Distribution center* to exist. This fails to consider that piping used primarily to deliver gas to customers who purchase it for consumption could be "transmission" based on operating stress or function.

With these considerations, the Associations propose the following modified definition for *Distribution center*. During the March 26-28, 2018 GPAC meeting, the GPAC directed PHMSA to consider incorporation of this definition into regulation<sup>8</sup>:

*Distribution center means the initial point where gas piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale, for example:*

- (1) at a metering location
  - (2) pressure reduction location, such as a gate station or custody transfer point, or
  - (3) where there is a reduction in the volume of gas, such as a lateral off a transmission line.
- (2) *The addition of a fourth criterion, "is voluntarily determined by the operator to be a transmission pipeline."*

The Associations support PHMSA's proposal, endorsed by the GPAC, to allow an operator to voluntarily designate pipeline laterals or other segments as a transmission pipeline. This is essential so that operators who have managed a segment in accordance with the transmission regulatory framework can continue to do so, even if the *Distribution center* definition would allow the segment to be classified as distribution. Additionally, this criterion allows an operator to designate a pipeline downstream of a distribution center that operates at less than 20% SMYS as a transmission line if the operator believes the risks to that pipeline are best managed through a Transmission Integrity Management Program.

- (3) *Changing "operates at a hoop stress" to "has an MAOP" of 20% percent or more of SMYS for the transmission line designation.*

The Associations are concerned about the potential change in the methodology used to determine percent SMYS for transmission line designation. The current methodology uses hoop stress, which is the

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<sup>8</sup> GPAC Meeting Final Voting Slides. March 26-28, 2018. Slide 16.

actual stress that acts along the circumference of the pipeline while the pipeline is operating at a specific pressure. The proposed regulatory language would revise the calculation to be based upon the Maximum Allowable Operating Pressure (MAOP), which represents the maximum pressure a pipeline or segment of a pipeline can operate at under Part 192. This is a significant change to a definition that has been in place since the inception of the federal pipeline safety code in 1970.

The Associations support ensuring the integrity of a line before dramatically increasing its operating pressure. In Subpart K of Part 192 there are a series of requirements that an operator must meet to ensure the integrity of a line before increasing its MAOP. If PHMSA is concerned about sudden, large increases in operating pressure within a pipeline's established MAOP, it should provide actual data and examples to support its concern and initiate a rulemaking to develop requirements similar to Subpart K for managing the scenario described during the March 26-28<sup>th</sup> GPAC meeting.<sup>9</sup> Changing the methodology for determining percent SMYS for the *Transmission line* definition is not the appropriate way to address concerns about operating practices; Subparts J and K address pipeline uprating and operations. PHMSA's proposed change will greatly increase the overall mileage of transmission pipeline with no defined impact in improving public safety.

Furthermore, PHMSA has not fully considered the impact that this change would have in its preliminary regulatory impact assessment. When installing new pipelines or pressure testing existing lines, operators often test to a higher pressure to establish a higher MAOP to accommodate for future growth or eliminate existing system constraints. These pipelines operate at distribution pressure and are managed within operator's distribution integrity management (DIMP) plans. In these cases, the proposed revision to the transmission pipeline definition may require operators to shift these pipelines into their transmission integrity management (TIMP) plans. Both the transition and the execution of the TIMP plans would increase the regulatory burden on operators, which is not accounted for in PHMSA's regulatory impact assessment and this change would dilute the impact of TIMP with low stress pipeline assessments.

In an informal survey, four operators estimated approximately 1700 miles of pipeline that would change operating classification from distribution to transmission as a result of this proposed change. For one of the operators, the impact is a 50% increase in the size of their transmission system. In these examples, the pipelines currently operate at pressures that produce low stress levels consistent with distribution pipelines. Shifting resources and focus from the Operator's DIMP to TIMP for these pipelines would not result in any measurable benefit in pipeline safety and is estimated to have a financial impact of an extra \$50 million dollars that is not captured in PHMSA's current regulatory impact assessment.

Finally, PHMSA's proposed revised language is not technically accurate: "has an MAOP of 20 percent or more of SMYS" is not a meaningful requirement. MAOP is a unit of pressure while SMYS is an indication of stress. If PHMSA insists on modifying the transmission line definition to refer to MAOP, technically correct language would be "has an MAOP *that produces a hoop stress* of 20 percent or more of SMYS."

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<sup>9</sup> In regard to % SMYS calculation for Transmission pipeline designation: 3-27-2018 GPAC Transcript pg. 267, Mr. Nanney: "...you can go 20 years and be at that lower operating pressure and then one day decide we're going to raise it 20 percent. And it could have been 20 years that you haven't raise that."



(4) The addition of the clause “or a connected series of pipelines.”

Finally, PHMSA introduced a new clause, “or a connected series of pipelines,” in the definition of a *Transmission line* during the March 26-28, 2018 GPAC meeting. Prior to this GPAC meeting, PHMSA had not proposed the addition of this clause nor was there any understanding as to the justification surrounding this proposed change. During the GPAC meeting, only after GPAC members questioned PHMSA about this addition, was an explanation provided. The reasoning offered pertained to a specific enforcement proceeding that was said to have occurred in the state of Alaska.<sup>10</sup> However, the Associations found no evidence of an enforcement case specific to “connected series of pipelines” in publicly available documents. Therefore, the Associations believe the addition of this clause should be struck from the definition of *Transmission lines* for three important reasons:

- (1) It is inappropriate for PHMSA to modify a definition in broadly applicable pipeline safety regulations due to an individual enforcement proceeding, especially since the details of this enforcement proceeding are unclear.
- (2) The addition adds confusion as to where a transmission line begins and ends. PHMSA did not provide GPAC members with background information on the intent of this change. This change could not only impact the demarcation between transmission and distribution lines, but also affect gathering lines, which have not yet been discussed by the GPAC.
- (3) PHMSA has not provided an estimate of the impacts this additional clause may have on the rulemaking. Additionally, this proposal did not go out for notice and comment in the proposed rule and the Associations believe the proposed addition increases the regulatory burden.

Taking into account the above comments, the Associations suggest the following definition for *Transmission line* for the transmission mandates rule.

*Transmission line* means a pipeline ~~or connected series of pipelines~~, other than a gathering line, that:

- (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility; or large volume customer that is not down-stream from a distribution center;
- (2) ~~has an MAOP~~ operates at a hoop stress of 20 percent or more of SMYS; or
- (3) transports gas within a storage field; or
- (4) is voluntarily determined by the operator to be a transmission pipeline.

Note: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

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<sup>10</sup> GPAC Meeting Transcript. March 27, 2018. Page 264. Mr. McLaren with PHMSA: “This discussion came about because of some enforcement actions in Alaska where the enforcement case ruling was that this one line was not a transmission line because it connected to another transmission line, and where clearly in our case, in our viewpoint was that these were all transmission lines. And the ruling went against us. We have looked at other cases like that and through the history of the definition of transmission line over the years. And this is, what we came up with is seeming acceptable over that history and to solve that point, that a transmission line can, indeed, connect to another transmission line. That is the intent. Thank you.”

## B. Occupied Site Definition

The GPAC endorsed the following revisions to the *Occupied site* definition: “Modifying the term ‘occupied sites’ in the MCA definition and at § 192.3 by removing ‘5 or more persons’ and the timeframe of 50 days and tying the requirement into the High Consequence Area (HCA) survey for ‘identified sites’ as discussed by members and PHMSA at the meeting. Such identification can be made through publicly available databases and class location surveys. PHMSA will consider the necessary sites and enforceability per direction by the members.”<sup>11</sup>

The Associations believe that it is essential for PHMSA to provide a **specific list** of outdoor sites that trigger the *Occupied site* definition. Per Member Gosman: “Because, essentially, these are areas where there are people not in buildings concerns me...But it seems to me what we're trying to do here is protect particular areas like beaches and playground and recreational areas. And those are easier, I would assume, to actually get the boundaries of and figure out. So, if we moved away from the people aspect of it, can we figure out a group of areas that are important to protect that are not protected now...”<sup>12</sup>

Additionally, PHMSA should provide clarity by focusing the *Occupied site* definition on small, well-defined areas of congregation. Certain outdoor areas may be very large geographically but have well-defined sites where people congregate. “Small, well-defined areas” are also referenced in the class 3 definition in § 192.5. Using this term in the *Occupied site* definition would connect MCA determination to existing class surveying programs, consistent with the GPAC recommendation.

The Associations remind PHMSA that the GPAC’s discussion on retaining the *Occupied site* definition was focused on outdoor sites. Buildings intended for human occupancy are addressed separately in the proposed MCA definition. Existing regulations already provide a list of particular buildings intended for human occupancy that meet the *Identified site* designation for HCAs. Hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities are explicitly listed as examples of sites that already trigger the HCA designation, regardless of population.

Based on the above commentary, the Associations recommend the following definition for *Occupied site*:

**Occupied site means a small, well-defined area of congregation at any of the following outside public areas or open public structures that an operator identifies through a publicly available database or class location survey and that does not meet the definition of *Identified Site* in § 192.903: Beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside of a religious facility.**

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<sup>11</sup> GPAC Meeting Final Voting Slides. March 2, 2018. Slide 4.

<sup>12</sup> GPAC Meeting Transcript. March 2, 2018. Pages 88 and 107.

### C. Pipeline Assessments: Inside and Outside of High Consequence Areas

Section 5 of the 2011 Pipeline Safety Act directed PHMSA to “evaluate whether integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas.”<sup>13</sup> The Associations support PHMSA addressing this mandate through the codification of proposed § 192.710 – *Pipeline assessments*. The Associations believe it also is important to ensure consistency and clarity throughout pipeline safety regulations by codifying the same assessment requirements within Subpart O – *Gas Transmission Integrity Management* as those proposed in § 192.710 for assessments outside of HCAs. Therefore, the Associations believe PHMSA should include its proposed changes to §192.710 and §192.921 as well as changes to § 192.937 in the transmission mandates rule. Additionally, the Associations believe it is important that PHMSA incorporate in the transmission mandates rule certain proposed new sections that provide specific details on how an operator is to perform various assessment methods.

It is not necessary for PHMSA to incorporate any changes related to direct assessment methodologies (§ 192.923, § 192.927 and § 192.929) in the transmission mandates rule as these sections already exist in current regulations. The Associations support PHMSA’s proposed modifications to these sections, as endorsed by the GPAC, but these modifications should be included in the second rule.

Similarly, new anomaly response and repair criteria for pipelines fall outside of PHMSA’s intended scope for the transmission mandates rule. There are existing anomaly response and repair requirements for pipelines outside of HCAs in § 192.711 – *Transmission lines: General requirements for repair procedures* and § 192.713 – *Transmission lines: Permanent field repair of imperfections and damages*. Therefore, PHMSA should address proposed changes to § 192.485, § 192.711, § 192.713 and § 192.933 in the second transmission rule.

The Associations suggest the following proposed sections related to integrity assessments be included in PHMSA’s transmission mandates rule.

- § 192.506 – *Transmission lines: Spike hydrostatic pressure testing for existing steel pipe with integrity threats.*
- § 192.710 – *Pipeline assessments*
- § 192.921- *How is the baseline assessment to be conducted*
- § 192.937 – *What is a continual process of evaluation and assessment to maintain a pipelines integrity?*
- Appendix F – *Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)*

In Section III below, the Associations have provided suggested modified regulatory text that reflects the votes and discussion from the GPAC meetings and the necessary edits to ensure consistency in assessment requirements throughout the regulations.

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<sup>13</sup> Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. Section 5. Integrity Management.

#### D. Moderate Consequence Area Application: Able to Accommodate In-Line Inspection

PHMSA has proposed to include Moderate Consequence Areas (MCAs) in two sections of this first rulemaking: § 192.624 - *Maximum allowable operating pressure verification: Onshore steel transmission pipelines* and § 192.710 - *Pipeline Assessments*. In both instances PHMSA includes the following qualifier, “if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (i.e., ‘smart pigs’).”

During the March 26-28 GPAC Meeting, the GPAC voted that PHMSA will “consider adding ‘free-swimming’ to the definition for ‘pipe segment can accommodate inspection by means of an instrumented in-line inspection tool’ per committee comments at the meeting.” Additionally, during the meeting PHMSA stated that they plan to include discussion in the preamble of the Final Rule on the meaning of *Pipe segment can accommodate inspection by means of instrumented inline inspection tools*. PHMSA states that this qualifier is intended to mean “a pipeline that can accommodate ... without any permanent physical modification of the pipeline.”

The Associations believe additional details are necessary to provide clarity as to the true intent of this qualifier. Not only should the pipeline be able to accommodate an in-line inspection device, but the device should also (1) be able to assess the pipeline fully and (2) traverse the pipeline under existing flow and pressure conditions. Otherwise “accommodating” the tool has no value, as operators will not be able to meaningfully assess the pipeline using an in-line inspection tool.

The Associations ask that PHMSA consider adding details regarding the meaning of “can accommodate inline inspection...” directly into the applicability sections of § 192.624(a) and § 192.710(a). It is important that PHMSA’s true intent is captured in the regulatory code versus only providing guidance in the preamble of the Final Rule. PHMSA’s intent for the qualifier greatly impacts the scope and impact of this rulemaking.

The associations offer the following regulatory language for PHMSA’s consideration:

A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of **free-swimming, commercially available** instrumented in-line inspection tools (i.e. smart pigs) **that can travel (using flow and pressure conditions encountered in normal operations) the length of the pipeline segment, inspect the entire circumference of the pipe, capture and record or transmit relevant, interpretable inspection data in sufficient detail for further evaluation of anomalies** **without permanent modifications to the pipe segment**.

#### E. MAOP Determination and MAOP Reconfirmation (§ 192.619 and § 192.624)

During the GPAC meeting, PHMSA and the GPAC discussed various important issues related to PHMSA's proposed maximum allowable operating pressure (MAOP) reconfirmation requirements for transmission lines. The Associations appreciate PHMSA clarifying the applicability of Traceable, Verifiable, and Complete (TVC) records<sup>14</sup>, as well as limiting MAOP reconfirmation requirements to onshore steel transmission pipelines.<sup>15</sup> The changes discussed in the meeting, and highlighted below, allow operators to successfully implement the practices for determining and reconfirming MAOP:

- (1) PHMSA should reference §192.624 within §192.619(a) to ensure operators can use the methods outlined within § 192.624 to confirm the MAOP of a pipe segment.
- (2) For “grandfathered” segments with adequate records, PHMSA should limit the applicability of MAOP reconfirmation to pipeline segments with an MAOP that produces a hoop stress greater than 30% of SMYS.
- (3) PHMSA should include a notification procedure for operators to extend the timeline for MAOP reconfirmation within § 192.624(b).
- (4) PHMSA should increase the look back period for pressure reductions, as outlined within Methods 2 and 5, to the implementation of the Gas Pipeline Integrity Management Regulation (Subpart O) on December 17, 2004.

- (1) PHMSA should reference § 192.624 within § 192.619(a) to ensure operators can use the methods outlined within § 192.624 to confirm the MAOP of a pipe segment.

The Associations appreciate PHMSA considering adding language within § 192.619(a) which would clarify that pipe segments that comply with any of the MAOP reconfirmation methods outlined within § 192.624 satisfy the § 192.619 requirements for a pressure test record, and therefore have a valid MAOP. In the March 26-28, 2018 GPAC meeting, the GPAC members, as well as public commenters, provided comments to support modifying the existing language in § 192.619(a).<sup>16</sup> As currently written, it is unclear whether an operator that has conducted MAOP reconfirmation using a method other than a pressure test would be in compliance with § 192.619(a). The Associations believe adding a reference to § 192.624 in § 192.619(a) confirms that an operator who conducts MAOP reconfirmation using any method allowed in § 192.624 is not required to take additional action to confirm MAOP.

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<sup>14</sup> GPAC Meeting Transcript. March 26, 2018. Pages 180-181. Mr. Nanney with PHMSA: “We would use the information we have to make the decision about the test. It may not be all of 192.607 for every mile of that hydrotest, but we would gather that data over time.”

<sup>15</sup> GPAC Meeting Final Voting Slides. March 26-28, 2018. Slide 10.

<sup>16</sup> GPAC Meeting Transcript. March 27, 2018. Pages 140-141. Ms. Kurilla with APGA: “I actually find 619(e) unnecessary, although I understand why PHMSA is including it. It's really to ensure that everyone understands you have essentially three ways to establish your MAOP now. You have 619(a) which is the lowest of the four; you have 619(c), the grandfather clause for still those pipelines that are allowed to use that; and now you have 624. So I'd really encourage PHMSA to look at the language in 619(a) and just add 624 there. And I don't think you need 619(e). All 619(e) does now is point operators to 624.”

Adding a reference to § 192.624 in § 192.619(a) also accomplishes a similar result as PHMSA's proposed language in § 192.619(e). Therefore, PHMSA's proposed § 192.619(e) is no longer needed and can be removed.

- (2) *For grandfathered segments with adequate records, PHMSA should limit the applicability of MAOP reconfirmation requirements to pipeline segments with an MAOP that produces a hoop stress greater than 30% of SMYS*

The Associations appreciate PHMSA's proposed revision to § 192.624(a)(3) which would limit its applicability to pipeline segments with an MAOP that produces a hoop stress greater than 30% of SMYS. This means that MAOP reconfirmation would not be required for a grandfathered segment that has a TVC operating history record to support the grandfathered MAOP (in accordance with § 192.619(c)), if the segment has an MAOP that produces a hoop stress greater than 30% of SMYS.

Stakeholders generally accept 30% of SMYS as the "low-stress" boundary between leaks and ruptures for pipeline defects. In 2001, the Gas Research Institute developed a report examining the boundary between leaks and ruptures. The report determined that pipelines operating at less than 30% of SMYS generally leak when they fail and that ruptures generally occur on pipelines operating at greater than 30% of SMYS.<sup>17</sup> The Gas Technology Institute, Battelle and Kiefner & Associates have continued to study this issue, validating the 30% of SMYS threshold.<sup>18,19,20</sup> Furthermore, PHMSA established 30% of SMYS as a low stress threshold for integrity assessments in the gas integrity management regulations in 49 C.F.R. § 192.941(a). Finally, in the 2011 Pipeline Safety Act, Congress recognized the low risk posed by pipelines operating below 30% of SMYS and mandated that PHMSA "issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in HCAs and operating at a pressure greater than 30 percent of SMYS."<sup>21</sup> Thus, PHMSA should exclude grandfathered pipelines that have a TVC operating history record to support the grandfathered MAOP and an MAOP that produces a hoop stress less than 30% of SMYS from the MAOP reconfirmation requirements. This would ensure consistency with Congress's direction, PHMSA's own regulations, and industry research and consensus.

The goal of MAOP reconfirmation is to confirm material strength for pipeline segments that do not have records of the Subpart J pressure test required for all new pipelines. Pressure testing confirms material strength by addressing critical, resident manufacturing and construction anomalies. As discussed

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<sup>17</sup> Gas Research Institute, Leak Versus Rupture Considerations for Steel Low-Stress Pipelines, GRI-00/0232 (Jan. 2001).

<sup>18</sup> Gas Technology Institute, Leak-Rupture Boundary Determination, Final Report (May 4, 2011) (Including Leak Rupture Calculator and Training Manual).

<sup>19</sup> Battelle, under contract for The INGAA Foundation in conjunction with American Gas Foundation, Integrity Characteristics for Vintage Pipelines (2005).  
<https://primis.phmsa.dot.gov/gasimp/docs/IntegrityCharacteristicsOfVintagePipelinesLBCover.pdf>.

<sup>20</sup> Kiefner & Associates, Inc., under contract for Gas Technology Institute, Numerical Modeling and Validation for Determination of the Leak/Rupture Boundary for Low-Stress Pipelines (2010).

<sup>21</sup> 49 U.S.C. § 60139(d)(1)

during the GPAC meeting, ruptures of gas pipelines operating below 30% SMYS are rare<sup>22</sup>, and even those that have occurred were generally not associated with the manufacturing and construction threats that pressure testing is intended to address.<sup>23</sup> In a 2013 report, Kiefner & Associates and Kleinfelder identified nine in-service incidents occurring on gas pipelines operating below 30% SMYS (including transmission, distribution and gathering) going back to approximately 1990.<sup>24</sup> These incidents were caused by corrosion and outside force damage (such as mechanical damage and earth movement), not by manufacturing-or construction-related issues.

MAOP reconfirmation is not the appropriate way to manage the threats that lead to ruptures on low SMYS pipelines, particularly the time-dependent threat of corrosion. These threats are managed through ongoing corrosion control, maintenance, and integrity management activities. In fact, the GPAC approved a series of more rigorous corrosion control requirements for all transmission pipelines at the June 2017 GPAC meeting (within 49 CFR 192 Subpart I: *Requirements for Corrosion Control*), which will further enhance corrosion control for ongoing operations. As indicated in previous comments, the Associations support the additional corrosion control regulations as voted on by the GPAC in June 2017.<sup>25</sup> The Associations emphasize that Subpart I is the appropriate place to address the relevant corrosion threats for pipeline segments outside of HCAs with an MAOP that produces a hoop stress less than 30% of SMYS.

During the March 26-28 GPAC meeting, the GPAC directed PHMSA to further analyze the costs and benefits of requiring MAOP reconfirmation for pipeline segments not covered by a subpart O TIMP plan and that have an MAOP that produces a hoop stress less than 30% of SMYS.<sup>26</sup> These low-stress segments tend to have smaller diameters and tend to be directly involved in the delivery of natural gas to end users. Due to the location and use of these pipelines, significant maintenance tasks, such as those proposed for MAOP reconfirmation, will result in particularly severe disruptions to customers. Many of these pipelines are one-way feeds and the only supply of gas, requiring temporary bypasses or use of multiple LNG/CNG trailers to be used to maintain gas service during MAOP reconfirmation activities. In addition, many of

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<sup>22</sup> Regarding the rarity of ruptures below 30% SMYS:

- GPAC Meeting Transcript. December 14, 2017. Pages 232-233. Mr. McLaren with PHMSA: “Well, the 30-percent SMYS has traditionally been identified as the ratio where you would go from a leak to a rupture, not wanting a rupture.”
- GPAC Meeting Transcript. December 14, 2017. Pages 237. Member Zamarin: “The 30-percent SMYS criteria is a criteria that has been established through a lot of research and a lot of analysis that demonstrates that, for the vast, vast majority, there is a de minimis amount of risk below that stress level that a pipeline would fail catastrophically and cause a significant impact to life and property.”
- Member Brownstein (12/15/17 Transcript, page 26-27): “So, we’re saying that the, that there’s a low probability of rupture below those pressures? Is that right?” Mr. Mayberry with PHMSA: “Much lower. It has happened, but lower.”

<sup>23</sup> GPAC Meeting Transcript. December 15, 2017. Pages 6-7. Member Drake: “The reason that was put into place at 30 percent was because of the pre-disposition to leak. And that [pressure] testing wasn’t going to help identify manufacturing issues that would grow to failure, or construction issues that would surface as a failure at that stress level.”

<sup>24</sup> Kiefner & Associates, Inc. and Kleinfelder, Study of pipelines that ruptured while operating at a hoop stress below 30% SMYS (February 2010).

<sup>25</sup> Comments on PHMSA’s Gas Pipeline Advisory Committee (GPAC) Meeting Held June 6-7, 2017, (filed by AGA, API and INGAA on August 2, 2017). <http://www.ingaa.org/Filings/RegulatoryFilings/32788.aspx>.

<sup>26</sup> GPAC Meeting Final Voting Slides. March 26-28, 2018. Slide 1.

these lines operate at lower pressures, have multiple valves and lateral lines, and include bends that make it difficult, if not impossible, to conduct inline inspection or remove water from the line following a hydrostatic test. These limitations will greatly increase the costs to reconfirm the MAOP for these segments.

Focusing on segments that have an MAOP that produces a hoop stress greater than 30% of SMYS for MAOP reconfirmation will enable significant resources to be directed towards higher impact safety work to address higher risk areas; the Associations estimate that this change would avoid billions of dollars in low-value work.<sup>27</sup> The Associations conducted a quick survey of members to determine the expected cost of including pipelines operating at a hoop stress below 30% of SMYS. Six members responded indicating they had approximately 400 miles (900 – 1600 segments) of pipeline in class 3 and 4 locations that were installed prior to 1970 and operating at a hoop stress below 30% of SMYS. The estimated cost per segment to conduct MAOP reconfirmation for these lines ranged from \$1,000,000 - \$1,250,000. For just these few companies, this results in an overall cost of \$900 million to \$2 billion.

(3) *PHMSA should include a notification procedure for operators to extend the timeline for MAOP reconfirmation within § 192.624(b).*

During the March 26-28, 2018 GPAC meeting, there was a discussion between the committee and PHMSA regarding an appropriate timeframe for conducting MAOP reconfirmation on segments that become “in-scope” for MAOP reconfirmation after the initial 15-year implement period (e.g., where the construction of new residences or businesses triggers a class location change). The GPAC discussed operational and construction constraints for scheduling MAOP reconfirmation. The Associations appreciate PHMSA allowing operators four years to reconfirm the MAOP of pipe segments that first meet the conditions in § 192.624(a) after the initial 15-year implementation period. Construction, environmental, or operations constraints could increase the time an operator needs to perform MAOP reconfirmation beyond four years. For this reason, the Associations believe that PHMSA should include a notification procedure for operators to extend the timeline for MAOP reconfirmation within § 192.624(b), similar to the notification procedure that the GPAC has endorsed for many other aspects of this rulemaking.<sup>28</sup>

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<sup>27</sup> Regarding the disproportionate cost associated with reconfirming MAOP for segments operating below 30% SMYS:

- GPAC Meeting Transcript. December 14, 2017. Page 197. Ms. Toczylowski with Consolidated Edison Company of New York: “As proposed, Con Edison’s only viable option to comply with this proposed regulation is to replace our entire transmission system.... As written, the cost to comply with this section of the rule will cost Con Edison and our customers over \$2.5 billion in current-day dollars. In comparison, if the rule was applied to pipe greater than 30-percent SMYS, the cost would be \$400 million.”
- GPAC Meeting Transcript. December 14, 2017. Page 195. Mr. Chittick with TransCanada: “As identified in the presentation, about 25 percent of the mileage of pipe that requires reconfirmation is within this grouping, small diameter, low pressure, low risk. When I look at the TransCanada system, on one of our pipelines we have 750 segments spread out amongst 250 pipelines that fall into this category. And the option of derating by 10 percent just isn’t practical. These pipelines form part of overall networks, and we can’t derate them readily by 10 percent.”

<sup>28</sup> See conversation on pages 143-146 of March 26, 2018 GPAC Meeting Transcript. Per Member Allen: “Just to point out, in previous meetings we have some language already in place regarding no objection within 90 days or something like that. It just feels like we could reuse that language in this situation.”



(4) PHMSA should increase the look back period for Methods 2 and 5 in § 192.624(c)(2) and § 192.624(c)(5).

During the March 26 – 28, 2018 GPAC meeting, PHMSA proposed and the GPAC endorsed extending the look back period upon which pressure reductions for MAOP reconfirmation must be based from 18 months to 5 years prior to the effective date of the final rule. The Associations appreciate PHMSA revising the look back period but believe that a five-year limitation still penalizes operators who have proactively reduced operating pressure. The Associations recommend that PHMSA increase the look back period for MAOP reconfirmation pressure reductions, for both Methods 2 and 5, to the implementation of the Gas Pipeline Integrity Management Regulation (Subpart O) on December 17, 2004. Many operators have proactively reduced operating pressures since 2004 as part of integrity management programs.<sup>29</sup> Further reductions would be duplicative and unnecessary to reconfirm MAOP.

For example, five operators indicated to the Associations that they have reduced pressure, to levels consistent with proposed §192.624(c)(5) requirements, on approximately 100 independent pipe segments (combined), totaling approximately 800 miles. In many instances, further reductions are not even possible if the pipeline is to continue serving its existing load.<sup>30</sup>

If PHMSA decides to retain the five-year lookback period, it is inappropriate to tie this lookback period to the effective date of the final rule. It often takes several years for significant rulemakings to move through the PHMSA, Department of Transportation and White House Office of Management and Budget review processes. If an operator decides to proactively take a pressure reduction for MAOP reconfirmation today, would that operator be assured that the pressure reduction would comply with the eventual MAOP reconfirmation regulation? What if an operator began working on MAOP reconfirmation and implementing pressure reductions in 2016, when the NPRM was published? While the Associations strongly believe that the lookback period should extend to the implementation of the Gas Pipeline Integrity Management Regulation (Subpart O) on December 17, 2004, at a minimum, PHMSA should select a specific lookback date that is at least five years ago from today (for example, January 1, 2013).

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<sup>29</sup> GPAC Meeting Transcript. March 27, 2018. Page 13. Member Campbell: “So I think, for the most part, the reason we’ve done it [reduce pressure] is because we didn’t have the records to support the MAOP and we decided we didn’t need that higher MAOP.”

<sup>30</sup> GPAC Meeting Transcript. March 27, 2018. Pages 9-10. Member Campbell: “I know for a fact that many operators have reduced the pressure to meet the TIMP as part of their integrity management program. And I think the concern is from the operators is if you keep it at either an 18-month or a five-year look-back period, if I reduce that pressure seven years ago as a part of my integrity management program, then you know am I faced with having to reduce the pressure, again, to reconfirm MAOP? And I might not be able to do that and still hold my load.”

#### F. Fracture Mechanics Modeling (§ 192.712)

Fracture mechanics modeling has an important and specific role in preventing pipeline failures. It is a valuable tool for determining the predicted failure pressure and remaining life for cracks and crack-like defects. The Associations and our members are very supportive of PHMSA's proposal to strike § 192.624(d) *Fracture Mechanics for failure stress and crack growth analysis* and to move fracture mechanics to a new stand-alone section §192.712, and to allow the applicability of the fracture mechanics modeling process in § 192.712 to be defined in relevant sections.<sup>31</sup>

However, PHMSA's proposed language for the fracture mechanics modeling process in the NPRM is extremely convoluted and must be rewritten for clarity. The proposed language is unclear as to the required data inputs, methods and considerations for performing fracture mechanics modeling. For example, the first sentence of proposed § 192.624(d) contains 124 words. In Section III of these comments, the Associations offer alternative language to restate, in a clearer fashion, the fracture mechanics modeling process that PHMSA proposed in the NPRM.

Furthermore, for gas pipelines, considerations for cyclic fatigue-induced growth are not appropriate in most instances where fracture mechanics modeling is warranted, and this should be recognized within § 192.712. Gas pipelines generally have stable pressures and as a result are not typically susceptible to cyclic fatigue.<sup>32</sup> Cyclic fatigue is more typically found in liquids pipelines, which tend to have greater pressure swings that lead to fatigue. As a senior PHMSA engineer explained during PHMSA's June 8, 2016 webinar, "Gas pipelines normally don't have cyclic fatigue issues, so on many or most of the lines; this problem will not be too much of a factor."<sup>33</sup> Therefore, the Associations support PHMSA's proposal to develop a separate "Fatigue analysis and remaining life" paragraph, § 192.712(c).<sup>34</sup> The Associations believe this paragraph should describe required crack growth and remaining life calculation methods for when the operator determines that the pipeline segment is susceptible to cyclic fatigue or other loading conditions that warrant such calculations. The Associations have provided recommended language for this paragraph in Section III.

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<sup>31</sup> PHMSA, "GPAC-Slide Presentation -Gas Rule - March 26 to 28 Mtg 5 - FINAL", Page 43.

<sup>32</sup> M.J. Rosenfeld, & J.F. Kiefner, Pipeline Research Council International Inc., Basics of Metal Fatigue in Natural Gas Pipeline Systems – A Primer for Gas Operations, Contract PR-302-03152 (June 30, 2006); BMT Fleet Technology, Fatigue Considerations for Natural Gas Pipelines (June 30, 2016).

<sup>33</sup> Safety of the Nation's Gas Transmission Pipelines – NPRM (June 8, 2016).

<https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=117>.

<sup>34</sup> PHMSA, "GPAC-Slide Presentation -Gas Rule - March 26 to 28 Mtg 5 - FINAL", Page 70.

#### G. Single Sections for “Other Technology or Process” and “Notifications”

On numerous occasions during the GPAC meetings, PHMSA and the committee members discussed the value of codifying a process by which an operator can notify PHMSA of its plan to use “other technology or process” to meet the objectives of the new regulations. The Associations fully support the process endorsed by the GPAC for such notifications.<sup>35</sup> The Associations recommend that PHMSA consider streamlining and clarifying the code by adding a new “Other Technology or Process Notification” section at § 192.633 and a general “How does an operator notify PHMSA?” section at § 192.635. These sections should apply for all of Part 192 and be referenced for both existing and new code sections that require notification to PHMSA. Having single sections to address notifications will promote clarity for the proposed rules and streamline any future modifications to these requirements.

PHMSA proposed a new “Notifications” paragraph within § 192.624 (MAOP Reconfirmation), and there is an existing notifications section for pipelines covered by Subpart O at § 192.949. However, given that notifications will be required for activities unrelated to MAOP reconfirmation and for pipelines outside of HCAs, the notification requirements should be located in a separate section within a subpart that has broad applicability.

The following existing and proposed sections would need to be revised to reference the Associations’ proposed § 192.633 for “other technology or process”: § 192.506, § 192.607, § 192.624(c), § 192.712, §192.921, § 192.937, and § 192.939. The following existing and proposed sections would need be revised to reference the Associations’ proposed general notifications procedure at § 192.635: § 192.624(b), §192.909, and § 192.933.

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<sup>35</sup> <sup>35</sup> GPAC Meeting Final Voting Slides. December 14, 2017. Slide 2.

### III. Changes to Regulatory Text of Proposed Rule: Incorporation of GPAC Votes & Industry Comments

Throughout the five meetings to discuss the transmission rules, the GPAC generally voted on concepts, rather than specific language. Therefore, the Associations provide the following modifications to the regulatory text of the transmission mandates rule for PHMSA's consideration. The Associations believe the modifications shown in **red** reflect the changes to the proposals from the NPRM that were endorsed by the GPAC during the five meetings. The Associations have also identified additional concerns that were not voted on by the GPAC, shown in **blue**, but were shared during public comment or identified through written comments by the Associations. Text without markup is identical to the language proposed in PHMSA's 2016 "Safety of Gas Transmission and Gathering Pipelines" NPRM.

#### PART 191 – TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL REPORTS, INCIDENT REPORTS, AND SAFETY-RELATED CONDITION REPORTS

##### §191.1 Scope.

- (a) This part prescribes requirements for the reporting of incidents, safety-related conditions, exceedances of maximum allowable operating pressure (MAOP), annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of gas pipeline facilities located in the United States or Puerto Rico, including pipelines within the limits of the Outer Continental Shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331). ~~This part applies to offshore gathering lines and to onshore gathering lines, whether designated as "regulated onshore gathering lines" or not (as determined in §192.8).~~
- (b) This part does not apply to—
- (1) Offshore gathering of gas in State waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;
  - (2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9; ~~or~~
  - (3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator; or
  - (4) ~~Sections 191.22(b) and 191.29 do not apply to gathering of gas~~ Onshore gathering of gas—

PHMSA has announced that it will address issues pertaining to gas gathering pipelines in a separate GPAC meeting and final rule. Therefore, the references to gas gathering pipelines in § 191.1 should not be modified in the transmission mandates rule. The Associations' redlines retain the current language in § 191.1 related to gas gathering. (See "Gas Rule Split-Out" presentation from Mr. Mayberry with PHMSA, March 26, 2018.)

Also, PHMSA should review the current draft of the ongoing effort to develop a consensus standard on gas gathering line safety requirements. There will be impacts to reporting due to that document.

- (i) Through a pipeline that operates at less than 0 psig (0 kPa);
- (ii) Through a pipeline that is not a regulated onshore gathering line (as determined in §192.8 of this subchapter); and
- (iii) Within inlets of the Gulf of Mexico, except for the requirements in §192.612.

**§191.23 Reporting safety-related conditions.**

- (a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with §191.25 the existence of any of the following safety-related conditions involving facilities in service:
- (1) In the case of a pipeline (other than an LNG facility) that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result.
  - (2) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline or the structural integrity or reliability of an LNG facility that contains, controls, or processes gas or LNG.
  - (3) Any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes gas or LNG.
  - (4) Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength.
  - (5) Any malfunction or operating error that causes the pressure of a distribution or gathering pipeline or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the margin (build-up) allowed for operation of pressure limiting or control devices.
  - (6) A leak in a pipeline or LNG facility that contains or processes gas or LNG that constitutes an emergency.
  - (7) Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank.
  - (8) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline or an LNG facility that contains or processes gas or LNG.
  - (9) For transmission pipelines, each exceedance of the maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in §§192.201, 192.620(e), and 192.739, as applicable.
- (b) A report is not required for any safety-related condition that—
- (1) Exists on a master meter system or a customer-owned service line;
  - (2) Is an incident or results in an incident before the deadline for filing the safety-related condition report;
  - (3) Exists on a pipeline (other than an LNG facility) that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or
  - (4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline and any condition under paragraph (a)(9) of this section.

**§191.25 Filing safety-related condition reports.**

- (a) Each report of a safety-related condition under §191.23(a)(1) through (8) must be filed (received by the Associate Administrator, OPS) within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reports may be transmitted by electronic mail to *InformationResourcesManager@dot.gov* or by facsimile at (202) 366-7128.
- (b) Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in §191.23(a)(9) for a gas transmission pipeline must be reported within five calendar days of the exceedance using the reporting methods and report requirements described in §191.25(c).
- (c) Reports may be filed by emailing information to *InformationResourcesManager@dot.gov* or by fax to (202) 366-7128. The report must be headed "Safety-Related Condition Report" or for §191.23(a)(9) "Maximum Allowable Operating Pressure Exceedances", and provide the following information:
  - (1) Name, principal address, and operator identification number (OPID) of operator.
  - (2) Date of report.
  - (3) Name, job title, and business telephone number of person submitting the report.
  - (4) Name, job title, and business telephone number of person who determined that the condition exists.
  - (5) Date condition was discovered and date condition was first determined to exist.
  - (6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.
  - (7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.
  - (8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

**§191.29 National Pipeline Mapping System.**

- (a) Each operator of a gas transmission pipeline or liquefied natural gas facility must provide the following geospatial data to PHMSA for that pipeline or facility:
  - (1) Geospatial data, attributes, metadata and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS Operator Standards Manual available at [www.npms.phmsa.dot.gov](http://www.npms.phmsa.dot.gov) or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595.
  - (2) The name of and address for the operator.
  - (3) The name and contact information of a pipeline company employee, to be displayed on a public Web site, who will serve as a contact for questions from the general public about the operator's NPMS data.
- (b) The information required in paragraph (a) of this section must be submitted each year, on or before March 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year's submission, the operator must comply with the guidance provided in the NPMS Operator Standards manual available at [www.npms.phmsa.dot.gov](http://www.npms.phmsa.dot.gov) or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595.
- (c) This section does not apply to gathering lines.



## PART 192 – TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

### Subpart A – General

#### §192.3 Definitions.

(Note: The Associations have only addressed definitions that PHMSA proposed to add or modify and that pertain to gas transmission pipelines. The Associations have only addressed the definitions that are relevant to the transmission mandates rule.)

Distribution center means the initial point where gas piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale, for example:

- (1) at a metering location
- (2) pressure reduction location, such as a gate station or custody transfer point, or
- (3) where there is a reduction in the volume of gas, such as a lateral off a transmission line.

See “General Comments” on distribution center definition above.

~~Distribution center means a location where gas volumes are either metered or have pressure or volume reductions prior to delivery to customers through a distribution line.~~

Dry gas or dry natural gas means gas ~~with less than 7 pounds of water per million (MM) cubic feet and not subject to excessive upsets allowing electrolytes into the gas stream above its dew point and without condensed liquids.~~

Per March 26-28, 2018 Final GPAC Voting Slide 14, the GPAC approved the revised definition of “Dry gas or dry natural gas” as indicated.

Hard spot means an area on steel pipe material with a minimum dimension greater than two inches (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinell 327 HB or Vickers 345 HV10).

Per March 26-28, 2018 Final GPAC Voting Slide 21, the GPAC approved the revised definition of “Hard Spot” as indicated.

In-line inspection (ILI) means ~~the~~ an inspection of a pipeline from the interior of the pipe using an in-line inspection tool; ~~which is~~ also called *intelligent* or *smart pigging*.

**NOTE: This definition includes tethered and self-propelled inspection tools.**

Per March 26-28, 2018 Final GPAC Voting Slide 13, the GPAC approved the revised definition of “In-line inspection” as indicated on Slide 126 of PHMSA’s presentation for the meeting.

*In-line inspection tool or instrumented internal inspection device* means a an instrumented device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside in order to identify and characterize flaws to analyze pipeline integrity; ~~which is~~ also known as called ~~an intelligent or smart pig.~~

~~Legacy construction techniques mean usage of any historic, now abandoned, construction practice to construct or repair pipe segments, including any of the following techniques:~~

- ~~(1) Wrinkle bends;~~
- ~~(2) Miter joints exceeding three degrees;~~
- ~~(3) Dresser couplings;~~
- ~~(4) Non-standard fittings or field fabricated fittings (e.g., orange-peeled reducers) with unknown pressure ratings;~~
- ~~(5) Acetylene welds;~~
- ~~(6) Bell and spigots; or~~
- ~~(7) Puddle welds.~~

~~Legacy pipe means steel pipe manufactured using any of the following techniques, regardless of the date of manufacture:~~

- ~~(1) Low-Frequency Electric Resistance Welded (LF-ERW);~~
- ~~(2) Direct-Current Electric Resistance Welded (DC-ERW);~~
- ~~(3) Single Submerged Arc Welded (SSAW);~~
- ~~(4) Electric Flash Welded (EFW);~~
- ~~(5) Wrought iron;~~
- ~~(6) Pipe made from Bessemer steel; or~~
- ~~(7) Any pipe with a longitudinal joint factor, as defined in § 192.113, less than 1.0 (such as lap-welded pipe) or with a type of longitudinal joint that is unknown or cannot be determined, including pipe of unknown manufacturing specification.~~

*Moderate consequence area* means an onshore area that is within a potential impact circle, as defined in § 192.903, of a pipeline segment with a maximum allowable operating pressure that produces a hoop stress greater than or equal to 30 percent of specific minimum yield strength

Per March 26-28, 2018 Final GPAC Voting Slide 13, the GPAC approved the revised definition of “In-line inspection tool or instrumented internal inspection device” as indicated on Slide 127 of PHMSA’s presentation for the meeting.

Per March 26-28, 2018 Final GPAC Voting Slide 1, the GPAC approved the withdrawal of the “legacy construction techniques,” “legacy pipe,” and “modern pipe” definitions.

PHMSA should consider limiting the Moderate Consequence Area (MCA) definition to pipeline segments with an MAOP that produces a hoop stress greater than or equal to 30 percent of SMYS. The MCA definition is used to establish applicability in proposed § 192.624(a)(3) and § 192.710. However, both of these sections only apply to segments with an MAOP that produces a hoop stress greater than or equal to 30 percent of SMYS. Therefore, performing the surveying, data management and engineering work necessary to determine MCAs for segments with an MAOP that produces a hoop stress less than 30 percent of SMYS has no practical application, but represents a significant burden for operators.

Per March 2, 2018 Final GPAC Voting Slide 4, the GPAC approved the following revisions to the moderate consequence area definition:

- Changing the highway description to remove reference to “rights-of-way” and adding language so that the highway consists of “any portion of the paved surface, including shoulders,”
- Clarifying that highways with 4 or more lanes are included,
- Working with Federal Highway Administration to provide operators with clear information relative to the proposal.

~~and~~ containing five (5) or more buildings intended for human occupancy, an occupied site, or ~~a right-of-way for any portion of the paved surface, including shoulders, of~~ a designated interstate, freeway, expressway, and other principal ~~4-lane~~ arterial roadway with four or more lanes as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures*, and ~~that~~ does not meet the definition of high consequence area, as defined in § 192.903. The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an occupied site, five (5) or more buildings intended for human occupancy, or ~~a right-of-way for any portion of the paved surface, including shoulders, of~~ a designated interstate, freeway, expressway, and other principal ~~4-lane~~ arterial roadway with four or more lanes, to the outermost edge of the last contiguous potential impact circle that contains either an occupied site, five (5) or more buildings intended for human occupancy, or ~~a right-of-way for any portion of the paved surface, including shoulders, of~~ a designated interstate, freeway, expressway, or other principal ~~4-lane~~ arterial roadway with four or more lanes.

~~Modern pipe means any steel pipe that it is not legacy pipe, regardless of the date of manufacture, and has a longitudinal joint factor of 1.0 as defined in § 192.113. Modern pipe refers to all pipe that is not legacy pipe.~~

Occupied site means a small, well-defined area of congregation at any of the following outside public areas or open public structures that an operator identifies through a publicly available database or class location survey and that does not meet the definition of *Identified Site* in § 192.903: Beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside of a religious facility.

- ~~(1) An outside area or open structure that is occupied by five (5) or more persons on at least 50 days in any twelve (12) month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or~~
- ~~(2) A building that is occupied by five (5) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12) month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks.~~

*Transmission line* means a pipeline ~~or connected series of pipelines~~, other than a gathering line, that:

- (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility; or large volume customer that is not down-stream from a distribution center;
- (2) ~~has an MAOP~~ operates at a hoop stress of 20 percent or more of SMYS; or
- (3) transports gas within a storage field; or
- (4) is voluntarily determined by the operator to be a transmission pipeline.

See "General Comments" on transmission line definition above.

Per March 26-28, 2018 Final GPAC Voting Slide 16, the GPAC endorse voluntary designation of lines as transmission.

Note: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

*Wrinkle bend* means a bend in the pipe that was formed in the field during construction such that the inside radius of the bend has one or more ripples with:

- (1) an amplitude greater than or equal to 1.5 times the wall thickness of the pipe, measured from peak to valley of the ripple or
- (2) with ripples less than 1.5 times the wall thickness of the pipe and with a wrinkle length (peak to peak) to wrinkle height (peak to valley) ratio under 12.
- (3) If the length of the wrinkle bend cannot be reliably determined, then the following definition should be used:

*Wrinkle bend* means a bend in the pipe where  $(h/D)*100$  exceeds 2 when  $S$  is less than 37,000 psi (255 MPa), where  $(h/D)*100$  exceeds  $\left(\frac{47,000-S}{10,000} + 1\right)$  for psi  $\left[\left(\frac{324-S}{69} + 1\right)\right]$  for MPa] when  $S$  is greater than 37,000 psi (255 MPa) but less than 47,000 psi (324 MPa), and where  $(h/D)*100$  exceeds 1 when  $S$  is 47,000 psi (324 MPa) or more.

- where  $D$  is the outside diameter of the pipe, in. (mm),
- $h$  is the crest-to-trough height of the ripple, in. (mm), and
- $S$  is the maximum operating hoop stress, psi ( $S/145$ , MPa).

§192.5 Class locations.

- (a) This section classifies pipeline locations for purposes of this part. The following criteria apply to classifications under this section.
- (1) A “class location unit” is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1- mile (1.6 kilometers) length of pipeline.
  - (2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.
- (b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:
- (1) A Class 1 location is:
    - (i) An offshore area; or
    - (ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.
  - (2) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.
  - (3) A Class 3 location is:
    - (i) Any class location unit that has 46 or more buildings intended for human occupancy; or
    - (ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)
  - (4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.
- (c) The length of Class locations 2, 3, and 4 may be adjusted as follows:
- (1) A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.
  - (2) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.
- (d) Records for transmission pipelines documenting **current** class locations and demonstrating how an operator determined **current** class locations in accordance with this section must be retained for the life of the pipeline.

Per June 6-7, 2017 Final GPAC Voting Slide 48,  
“clarify that documentation be required for the  
current class location.

§192.7 What documents are incorporated by reference partly or wholly in this part?

(a) This part prescribes standards, or portions thereof, incorporated by reference into this part with the approval of the Director of the Federal Register in 5 U.S.C. 552(a) and 1 CFR part 51. The materials listed in this section have the full force of law. To enforce any edition other than that specified in this section, PHMSA must publish a notice of change in the FEDERAL REGISTER.

(1) *Availability of standards incorporated by reference.* All of the materials incorporated by reference are available for inspection from several sources, including the following:

- (i) The Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. For more information contact 202-366-4046 or go to the PHMSA Web site at: <http://www.phmsa.dot.gov/pipeline/regs>.
- (ii) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030 or go to the NARA Web site at: [http://www.archives.gov/federal\\_register/code\\_of\\_federal\\_regulations/ibr\\_locations.html](http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html).
- (iii) Copies of standards incorporated by reference in this part can also be purchased or are otherwise made available from the respective standards-developing organization at the addresses provided in the centralized IBR section below.

(2) [Reserved]

**(b) [Same as current]**

(c) [Same as current]

(d) [Same as current]

(e) [Same as current]

(f) [Same as current]

**(g) [Same as current]**

(h) [Same as current]

(i) [Same as current]

(j) [Same as current]

~~(k) Battelle Memorial Institute, 505 King Avenue, Columbus, OH, 43201, phone (800) 201-2011, <http://www.battelle.org/>.~~

~~(1) Battelle's Experience with ERW and Flash-Welding Seam Failures: Causes and Implications (Task 1.4), IBR approved for §192.624(c) and (d).~~

~~(2) Battelle Memorial Institute, "Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams" (Subtask 2.4), IBR approved for §192.624(c) and (d).~~

~~(3) Battelle Final Report No. 13-021, "Predicting Times to Failures for ERW Seam Defects that Grow by Pressure Cycle Induced Fatigue (Subtask 2.5), IBR approved for §192.624(c) and (d).~~

~~(4) Battelle Memorial Institute, "Final Summary Report and recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1" (Task 4.5), IBR approved for §192.624(c) and (d).~~

The new references proposed for incorporation in § 192.7(b) and (g) do not pertain to the topics that PHMSA has proposed to include in the transmission mandates rule. PHMSA should incorporate these references in the second transmission final rule.

PHMSA should remove the references to the Battelle reports, which PHMSA proposes to include as fracture mechanics modeling methods. While these reports are very helpful technical resources that should be made available on PHMSA's website, they are not fracture mechanics models in and of themselves. The Associations recommend an appropriate list of fracture mechanics models in § 192.712 below.

**§192.13 What general requirements apply to pipelines regulated under this part?**

(a) No person may operate a segment of pipeline listed in the first column that is readied for service after the date in the second column, unless:

- (1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or
- (2) The pipeline qualifies for use under this part according to the requirements in §192.14.

PHMSA should make **no changes** to current §192.13 in the gas transmission mandates rules. PHMSA has announced that gas gathering topics (§192.13(a),(b)) will be addressed in a separate rule. PHMSA has announced that management of change (§192.13(d)) will be addressed in the second gas transmission rulemaking. The GPAC endorsed eliminating proposed §192.13(e). The Associations' redlines retain the current language in § 192.13.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006	March 15 2007.
<del>Regulated onshore gathering line to which this part did not apply until <i>(insert effective date of the rule)</i></del>	<del><i>(insert effective date of the rule plus one year)</i></del>
All other pipelines	March 12, 1971.

(b) No person may operate a segment of pipeline listed in the first column that is replaced, relocated, or otherwise changed after the date in the second column, unless the replacement, relocation or change has been made according to the requirements in this part.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006	March 15, 2007.
<del>Regulated onshore gathering line to which this part did not apply until <i>(insert effective date of the rule)</i></del>	<del><i>(insert effective date of the rule plus one year).</i></del>
All other pipelines	November 12, 1970.

(c) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.

~~(d) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, risks to the public and environment as an integral~~

PHMSA's proposed addition of Management of Change requirements falls outside of the scope of the first rulemaking.

~~part of managing pipeline design, construction, operation, maintenance, and integrity, including management of change. Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11, that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. A management of change process must include the following: (1) reason for change, (2) authority for approving changes, (3) analysis of implications, (4) acquisition of required work permits, (5) documentation, (6) communication of change to affected parties, (7) time limitations and (8) qualification of staff.~~

~~(e) Each operator must make and retain records that demonstrate compliance with this part.~~

~~(1) Operators of transmission pipelines must keep records for the retention period specified in Appendix A.~~

~~(2) Records must be reliable, traceable, verifiable, and complete.~~

~~(3) For pipeline material manufactured before *[insert effective date of the rule]* and for which records are not available, each operator must re-establish pipeline material documentation in accordance with the requirements of § 192.607.~~

Per March 2, 2018 Final GPAC  
Voting Slide 6, withdraw  
§192.13(e).



## **Subpart B – Materials**

§ 192.67 Records: Materials.

**For transmission pipe manufactured after [insert effective date of the final rule],** each operator ~~of transmission pipelines~~ must acquire and retain for the life of the pipeline the original steel pipe manufacturing records that document tests, inspections, and attributes required by the manufacturing specification in effect at the time the pipe was manufactured, including, but not limited to, yield strength, ultimate tensile strength, and chemical composition of materials for pipe in accordance with § 192.55.

Per March 2, 2018 Final GPAC Voting Slide 6, “Revise proposed § 192.67, § 192.127, and § 192.205 to clarify the effective date of the requirements.”

## **Subpart C – Pipe Design**

§ 192.127 Records: Pipe design.

**For transmission pipe manufactured after [insert effective date of the final rule],** each operator ~~of transmission pipelines~~ must make and retain for the life of the pipeline records documenting pipe design to withstand anticipated external pressures and loads in accordance with § 192.103 and determination of design pressure for steel pipe in accordance with § 192.105.

## **Subpart D – Design of Pipeline Components**

§ 192.205 Records: Pipeline components.

**For transmission components manufactured after [insert effective date of the final rule],** each operator ~~of transmission pipelines~~ must acquire and retain records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components **manufactured after [insert effective date of the final rule]** with material yield strength grades of 42,000 **and greater than 2 inches in nominal diameter** psi or greater must have records documenting the manufacturing specification in effect at the time of manufacture, including, but not limited to, yield strength, ultimate tensile strength, and chemical composition of materials.

Per March 2, 2018 Final GPAC Voting Slide 6, “Modify §192.205 to clarify that it applies to components greater than 2 inches in nominal diameter.”

## **Subpart E – Welding of Steel in Pipelines**

§192.227 Qualification of welders and welding operators.

- (a) Except as provided in paragraph (b) of this section, each welder or welding operator must be qualified in accordance with section 6, section 12, or Appendix A of API Std 1104 (incorporated by reference, see §192.7), or section IX of ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, see §192.7). However, a welder or welding operator qualified under an earlier edition than the edition listed in §192.7 may weld but may not re-qualify under that earlier edition.
- (b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.

- (c) **For transmission pipe installed after [insert effective date of the final rule], records ~~for transmission pipelines~~ demonstrating each individual welder qualification in accordance with this section must be retained for five years following installation ~~the life of the pipeline~~.**

Per June 6-7, 2017 Final GPAC Voting Slide 48, "Modify 192.227 and 192.285 to include an effective date and change retention period to five years.."

#### **Subpart F – Joining of Materials Other Than by Welding**

§192.285 Plastic pipe: Qualifying persons to make joints.

- (a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:
- (1) Appropriate training or experience in the use of the procedure; and
  - (2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.
- (b) The specimen joint must be:
- (1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and
  - (2) In the case of a heat fusion, solvent cement, or adhesive joint:
    - (i) Tested under any one of the test methods listed under §192.283(a) applicable to the type of joint and material being tested;
    - (ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or
    - (iii) Cut into at least 3 longitudinal straps, each of which is:
      - (A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and
      - (B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.
- (c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under §192.513.
- (d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this section.
- (e) For transmission pipelines **installed after [insert effective date of the final rule], records demonstrating plastic pipe joining qualifications in accordance with this section must be retained for five years following installation ~~the life of the pipeline~~.**

## **Subpart J – Test Requirements**

### **§192.503 General requirements.**

- (a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—
- (1) It has been tested in accordance with this subpart and ~~§§192.619, 192.620 or 192.624~~ to substantiate the maximum allowable operating pressure; and
  - (2) Each potentially hazardous leak has been located and eliminated.
- (b) The test medium must be liquid, air, natural gas, or inert gas that is—
- (1) Compatible with the material of which the pipeline is constructed;
  - (2) Relatively free of sedimentary materials; and
  - (3) Except for natural gas, nonflammable.
- (c) Except as provided in §192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Per March 26-28, 2018 Final  
GPAC Voting Slide 6:  
“Withdraw the proposed  
revision to §192.503.”

Class location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1	80	80
2	30	75
3	30	50
4	30	40

- (d) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.
- (e) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that:
- (1) The component was tested to at least the pressure required for the pipeline to which it is being added;
  - (2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or
  - (3) The component carries a pressure rating established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in §192.143.

§192.506 Transmission Lines: Spike ~~hydrostatic~~ pressure test for existing steel pipe with integrity threats

- a) Each segment of an existing steel pipeline that is operated at a hoop stress level of 30% of specified minimum yield strength or more and has been found to have time-dependent cracking, including stress corrosion cracking, must be strength tested by a spike ~~hydrostatic~~ pressure test unless the operator addresses the integrity threat by other means, such as in-line inspection or direct assessment. ~~cannot be addressed in accordance with this section to substantiate the proposed maximum allowable operating pressure.~~
- b) Operators must select a test medium consistent with 192.503(b)-(c). The spike hydrostatic pressure test must use water as the test medium.
- c) The baseline test pressure without the additional to be applied after the spike test ~~pressure~~ is the test pressure specified in §§ 192.619(a)(2), or 192.620(a)(2), ~~or 192.624~~, whichever applies.
- d) The test must be conducted by maintaining the pressure at or above the baseline test pressure for at least 8 hours, as specified in § 192.505 ~~(e)~~.
- e) After the test pressure stabilizes at the baseline pressure and within the first two hours of the 8-hour test interval, the ~~hydrostatic~~ pressure must be raised (spiked) to a minimum of the lesser of 1.50 times MAOP or ~~105%~~ 100% SMYS. This spike ~~hydrostatic~~ pressure test must be held for at least ~~30~~ 15 minutes.

PHMSA should consider not mandating water as the test medium for spike tests.

The Associations and our members understand the risks of using gaseous mediums for spike tests when assessing identified time-dependent cracking. However, the Associations want to ensure flexibility of the spike test procedure as described in § 192.506 to address unique circumstances, or in the event § 192.506 it is referenced for other uses in future regulations.

Per the March 2, 2018 GPAC Voting Slide 3, PHMSA will “revise the spike pressure test requirements proposed in 192.506 revise language to refer to time-dependent cracking.”

Per the March 26-28, 2018 GPAC Voting Slide 3, in 192.624 PHMSA will “delete paragraphs (i) and (iii) to remove spike testing for lines with suspected crack defects.” Additionally, per the March 26-28, 2018 GPAC Voting Slide 6, PHMSA will “revise the fracture mechanics requirements by striking references to 192.506 [spike pressure testing.]”

The Associations believe by removing these two references to spike pressure testing that pertain to MAOP reconfirmation, there is no need to reference MAOP in the spike pressure testing section.

§ 192.505(e) no longer exists in PHMSA’s regulations.

Per the March 2, 2018 GPAC Voting Slide 3, PHMSA will “revise the spike pressure test requirements proposed in 192.506 to change the minimum pressure to whichever is lesser: 100% SMYS or 1.5 times MAOP” and will “revise the spike pressure test requirements proposed in 192.506 to reduce the spike hold time to a minimum of 15 minutes after the spike pressure has stabilized.”

- f) ~~If the integrity threat being addressed by the spike test is of a time-dependent nature such as a cracking threat, t~~ The operator must establish an appropriate retest interval and conduct periodic retests at that interval using the same spike test pressure or other assessment that addresses the threat. The appropriate retest interval and periodic tests for the time-dependent threat must be determined in accordance with the methodology in § 192.712 624(d).

Consistent with PHMSA's proposed language in (a), operators may use other assessment methods, such as in-line inspection or direct assessment, to reassess the time-dependent cracking threat.

- g) Other Alternative Technology or Alternative Technical Evaluation Process - Operators may use other alternative technology or an alternative technical evaluation another process that provides a sound engineering basis for establishing a spike hydrostatic pressure test or equivalent. If an operator elects to use alternative technology or an alternative technical evaluation process, the operator must notify PHMSA at least ~~180~~ 90 days in advance of use in accordance with § 192.633. paragraph §192.624(e) of this section. The operator must submit the alternative technical evaluation to the Associate Administrator of Pipeline Safety with the notification and must obtain a "no objection letter" from the Associate Administrator of Pipeline Safety prior to usage of alternative technology or an alternative technical evaluation process. The notification must include the following details:

Rather than refer to the "notifications" paragraph within the MAOP reconfirmation section, PHMSA should establish a separate "notifications" section in Subpart L for all of Part 192. The Associations propose §§ 192.633 and 192.635. See discussion in General Comments around single notifications sections.

Per the March 2, 2018 GPAC Voting Slide 3, PHMSA will "revise the spike pressure test requirements proposed in 192.506 to revise proposed 192.506(g) to incorporate the same 'no objection' language the committee approved for 192.607 and with a timeframe of 90 days."

- (1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;
- (2) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered;
- (3) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;
- ~~(4) Assessment techniques and acceptance criteria;~~
- ~~(5) Remediation methods for assessment findings;~~

As proposed, the list of details to be included in the notification is unclear, excessive, and duplicative. §192.506 provides a process for performing spike testing; remediation methods and fracture mechanics modeling requirements are addressed elsewhere. Detailed descriptions of the alternative process/technology, procedures for tests and assessments, data requirements, and subject matter expert review provide ample information for PHMSA to determine whether it has an objection to an operator's proposal.

~~(6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;~~

~~(7) Procedures for remaining crack growth analysis and pipe segment life analysis for the time interval for additional assessments, as required; and~~

(8) Evidence of a review of all procedures and assessments by a **qualified technical** subject matter expert. ~~(s) in both metallurgy and fracture mechanics~~

Per the March 2, 2018 GPAC Voting Slide 3, PHMSA will “revise the spike pressure test requirements proposed in 192.506 to revise proposed 192.506(g)(8) to incorporate ‘qualified technical subject matter expert’ language at the SME requirements.”

**§192.517 Records.**

- (a) Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§192.505, 192.506 and 192.507. The record must contain at least the following information:
  - (1) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.
  - (2) Test medium used.
  - (3) Test pressure.
  - (4) Test duration.
  - (5) Pressure recording charts, or other record of pressure readings.
  - (6) Elevation variations, whenever significant for the particular test.
  - (7) Leaks and failures noted and their disposition.
- (b) Each operator must maintain a record of each test required by §§192.509, 192.511, and 192.513 for at least 5 years.

## **Subpart L – Operations**

§192.605 Procedural manual for operations, maintenance, and emergencies.

- (a) *General.* Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.
- (b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.
- (1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart M of this part.
  - (2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.
  - (3) Making construction records, maps, and operating history available to appropriate operating personnel.
  - (4) Gathering of data needed for reporting incidents under Part 191 of this chapter in a timely and effective manner.
  - (5) **Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices.**  
~~Operating pipeline controls and systems and operating and maintaining pressure relieving or pressure limiting devices, including those for starting up and shutting down any part of the pipeline, so that the MAOP limits as prescribed by this part cannot be exceeded by more than the margin (build-up) allowed for operation of pressure relieving devices or pressure limiting and control devices as specified in §§192.201, 192.620(e), 192.731, 192.739, or 192.743, whichever applies.~~
  - (6) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.
  - (7) Starting, operating and shutting down gas compressor units.
  - (8) Periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.
  - (9) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.
  - (10) Systematic and routine testing and inspection of pipe-type or bottle-type holders including—
    - (i) Provision for detecting external corrosion before the strength of the container has been impaired;
    - (ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and

Per March 26-28, 2018 Final GPAC Voting Slide 6: “Withdraw the proposed revision to §192.605(b)(5).” The Associations propose language is the existing language in §192.605(b)(5).



- (iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.
- (11) Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under §192.615(a)(3) specifically apply to these reports.
- (12) Implementing the applicable control room management procedures required by §192.631.
- (c) *Abnormal operation.* For transmission lines, the manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:
  - (1) Responding to, investigating, and correcting the cause of:
    - (i) Unintended closure of valves or shutdowns;
    - (ii) Increase or decrease in pressure or flow rate outside normal operating limits;
    - (iii) Loss of communications;
    - (iv) Operation of any safety device; and
    - (v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.
  - (2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.
  - (3) Notifying responsible operator personnel when notice of an abnormal operation is received.
  - (4) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.
  - (5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.
- (d) *Safety-related condition reports.* The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of §191.23 of this subchapter.
- (e) *Surveillance, emergency response, and accident investigation.* The procedures required by §§192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.

§ 192.607 Verification of Pipeline Material: Onshore steel transmission pipelines

(a) Whenever required or allowed in this Part and after [insert effective date of the final rule], this section prescribes a process for operators of onshore steel transmission pipelines to verify unknown material properties. Applicable Locations. Each operator must follow the requirements of paragraphs (b) through (d) of this section for each segment of onshore, steel, gas transmission pipeline installed before [insert the effective date of the rule] that does not have reliable, traceable, verifiable, and complete material documentation records for line pipe, valves, flanges, and components and meets any of the following conditions:

- (1) The pipeline is located in a High Consequence Area as defined in § 192.903; or
- (2) The pipeline is located in a class 3 or class 4 location

(b) ~~Material Documentation Plan.~~ Each operator must prepare a material documentation plan to implement all actions required by this section by [insert date that is 180 days after the effective date of the rule].

(b) ~~(c)~~ Material Documentation. For pipe properties verified using paragraph §192.607(c) of this section, Each operator must have and retain for the life of the pipeline reliable, traceable, verifiable, and complete records. documenting the following:

- (1) For line pipe and fittings, records must document diameter, wall thickness, grade (yield strength and ultimate tensile strength), chemical composition, seam type, coating type, and manufacturing specification.
- (2) For valves, records must document either the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating. For valves with pipe weld ends, records must document the valve material grade and weld end bevel condition to ensure compatibility with pipe end conditions;
- (3) For flanges, records must document either the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating, and the material grade and weld end bevel condition to ensure compatibility with pipe end conditions;

Per Final December 2017 GPAC voting language: PHMSA will “Clarify that material verification applies to onshore steel transmission lines only (and not distribution or gathering lines)”

Per Final December 2017 GPAC voting language: “In proposed paragraph (a), remove applicability criteria and make material verification a procedure for getting missing or inadequate records or verifying pipeline attributes if and when required by 192.624 or other code sections. The committee will discuss the applicability of 192.607 under each of the methods of MAOP verification discussed in 192.624 and other sections as appropriate.”

Per Final December 2017 GPAC voting language: “In proposed paragraph (b), delete requirements for creating a material verification program plan.”

Per Final December 2017 voting language: “In proposed paragraph (c), drop the list of mandatory attributes operators must verify but require operators to keep records developed through this material verification method.”

Per Mr. Nanney (12/14/17 Transcript): “... each operator would have to retain for the life of the pipeline traceable, verifiable and complete records documenting the pipe properties...established under this section. Whatever you use this section to get, we would expect you, of course, to keep those records and everything.”

~~(4) For components, records must document the applicable standards to which the component was manufactured to ensure pressure rating compatibility;~~

~~(c) (d)~~ **Verification of Material Properties.** For any material documentation records for line pipe, valves, flanges, and components ~~specified in paragraph (c) that are required to be verified this section that are not available~~, the operator must take the following actions to determine and verify the physical characteristics.

- (1) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for line pipe at ~~all~~ above ground locations.
- (2) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for buried line pipe at ~~all~~ excavations associated with replacements or relocations of pipe segments that are removed from service.
- (3) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for buried line pipe at ~~all~~ excavations associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, or maintenance, ~~or any other reason for which the pipe segment is exposed~~, except for segments exposed during excavation activities that are conducted to comply with in compliance with § 192.614, until completion of the minimum number of excavations as follows.

Per Final December 2017 GPAC voting language: PHMSA will “Retain flexibility to allow either destructive or non-destructive tests when verification is needed”

PHMSA agreed to consider deleting the requirement for testing when the pipe is exposed for “any other reason.” (6/7/17 transcript, Page 169.)

Per Final December 2017 GPAC voting language: “Clarify the applicability of 192.607(d)(3)(i).”

The Associations suggest that by removing the term “population” and adding §192.607(c)(3)(i)(C) below, operators can choose the sampling approach in §192.607(c)(3)(i)(A) and (B) or develop alternative sampling methods and submit a notice to PHMSA under §192.633. Several operators have already developed similar methodologies and position papers while conducting MAOP validation.

PHMSA should consider making 192.607(c)(3)(i) non-mandatory if this language is retained.

~~(i) the operator must define a separate population of undocumented or inadequately documented pipeline segments for each unique combination of the following attributes: wall thicknesses (within 10 percent of the smallest wall thickness in the population), grade, manufacturing process, pipe manufacturing dates (within a two-year interval) and construction dates (within a two-year interval).~~

- (i) Assessments must be proportionally spaced throughout the pipeline segment. Each length of the pipeline segment equal to 10 percent of the total length must contain 10 percent of the total number of required excavations, e.g. a 200 mile segment population would require 15 excavations for each 20 miles. For each population defined according to (i) above, The minimum number of excavations at which line pipe must be tested to verify pipeline material properties is the lesser of (A) or (B) below: the following:

- (A) 150 excavations; or  
 (B) If the segment is less than 150 miles, a number of excavations equal to the segment's population's pipeline mileage (i.e., one set of properties per mile), rounded up to the nearest whole number. ~~The mileage for this calculation is the cumulative mileage of pipeline segments in the population without reliable, traceable, verifiable, and complete material documentation.~~  
 (C) In lieu of (A) and (B) above, an operator may use another process and submit notification to PHMSA in accordance with 192.607(c)(6). The alternative process must establish a minimum 90% confidence level standard for any pipe material sampling process utilized.

Per Final December 2017 GPAC voting language: "Retain the opportunistic approach of obtaining unknown or undocumented material properties when excavations are performed for other repairs or other reasons, using a one-per-mile standard proposed by PHMSA, but allow operators to use their own statistical approach and submit a notification to PHMSA with their method. Establish a minimum standard of a 95% confidence level for operator statistical methods submitted to PHMSA." Also: "Revise the paragraph to accommodate situations where a single material verification test is needed (e.g. additional information is needed for an anomaly evaluation / repair)."

The GPAC endorsed a 95% confidence interval. However, the hazardous liquid rule proposed a 90% confidence interval for material properties. The Associations believe a 90% confidence interval is more appropriate. As such, the Associations suggest changing the confidence interval to 90% to be consistent with the hazardous liquids rule.

Final December 2017 GPAC voting language: "In proposed paragraph (c), drop the list of mandatory attributes operators must verify but require operators to keep records developed through this material verification method."

- (ii) At each excavation, ~~tests for material properties must determine diameter, wall thickness, yield strength, ultimate tensile strength, Charpy v notch toughness (where required for failure pressure and crack growth analysis), chemical properties, seam type, coating type, and must test for the presence of stress corrosion cracking, seam cracking, or selective seam weld corrosion using ultrasonic inspection, magnetic particle, liquid penetrant, or other appropriate non-destructive examination techniques.~~ Determination of material property values must conservatively account for measurement inaccuracy and uncertainty. ~~based upon the use of reliable engineering testing and analysis. comparison with destructive test results using unity charts.~~

- (iii) If non-destructive tests are performed to determine strength ~~or chemical composition~~, the operator must use methods, ~~tools~~, procedures, and techniques that have been ~~independently~~ validated by subject matter experts ~~and utilize calibrated equipment. in metallurgy and fracture mechanics to produce results that are accurate within 10% of the actual value with 95% confidence for strength values, within 25% of the actual value with 85% confidence for carbon percentage and within 20% of the actual value with 90% confidence for manganese, chromium, molybdenum, and vanadium percentage for the grade of steel being tested.~~

Chemical composition is not needed for MAOP reconfirmation or anomaly response calculations, the two areas where PHMSA proposed to reference §192.607.

Per Final December 2017 GPAC voting language: "Drop accuracy specifications (retain requirement that test methods must be validated and that calibrated equipment be used)."

- (iv) ~~The minimum number of test locations at each excavation or above-ground location is based on the number of joints of line pipe exposed, as follows:~~
- ~~(A) 10 joints or less: one set of tests for each joint.~~
  - ~~(B) 11 to 100 joints: one set of tests for each five joints, but not less than 10 sets of tests.~~
  - ~~(C) Over 100 joints: one set of tests for each 10 joints, but not less than 20 sets of tests.~~

Per Final December 2017 GPAC voting language: "Drop mandatory requirements for multiple test locations for large excavations (multiple joints within the same excavation)." Also, per Mr. Nanney (12/14/17 transcript pg. 53): "Also, we would drop the mandatory requirements for multiple locations for large excavations. In other words, it would only be one test in two quadrants. And then, for NDE tests, like I just said, we would reduce the number of quadrants from four to two for the test."

- (iv) For non-destructive tests, at each test location, a set of material properties tests must be conducted at a minimum of ~~five places in each circumferential quadrant of the pipe for a minimum total of 20 test readings at each pipe cylinder location. two circumferential quadrants of the pipe.~~

Per Final December 2017 GPAC voting language: "Reduce number of quadrants at which NDE tests must be made from 4 to 2." Still, the Associations note that API 5L, which is incorporated by reference in §192.7, requires testing of one quadrant.

- (v) For destructive tests, at each test location, a set of materials properties tests must be conducted on **two each** circumferential quadrants of a test pipe cylinder removed from each location., ~~for a minimum total of four tests at each location.~~

The Associations encourage PHMSA to revisit the proposed requirement to perform additional test if any test results are different than original assumptions. The Associations suggest if material verification yields more conservative material properties, operators should be allowed to apply these values instead of conducting additional testing.

- (vi) If the results of all tests conducted in accordance with paragraphs ~~(d)(3)(i) and (ii)(c)(3)(i)~~ of this section verify that material properties are consistent with all available information for each ~~population pipe segment or are less conservative than current assumptions,~~ then no additional excavations are necessary. However, if the test results identify line pipe with properties that are not consistent with existing information ~~expectations based on all available information for each population, then the operator must perform tests at additional excavations, and are more conservative than the current assumptions, then the operator must expand their material verification process and submit notification to PHMSA in accordance with 192.607(c)(6), or apply the more conservative values. The expanded process must establish a minimum 90% confidence level standard for any pipe material verification process utilized. The minimum number of excavations that must be tested depends on the number of inconsistencies observed as found tests and available operator records, in accordance with the following table.~~

Per Final December 2017 GPAC voting language: "Delete specified program requirements for how to address sampling failures and replace with a requirement for operators to determine how to deal with sample failures through an expanded sample program that is specific to their system and circumstances. Require notification to provide expanded sample program to PHMSA, and require operators establish a minimum standard that sampling programs must be based on a minimum 95% confidence level."

<del>Number of Excavations with Inconsistency Between Test Results and Existing Expectations Based on All Available Information for each Population</del>	<del>Minimum Number of Total Required Excavations for Population. The lesser of:</del>
<del>0</del>	<del>150 (or pipeline mileage)</del>
<del>1</del>	<del>225 (or pipeline mileage times 1.5)</del>
<del>2</del>	<del>300 (or pipeline mileage times 2)</del>
<del>&gt;2</del>	<del>350 or pipeline mileage times 2.3)</del>

- (vii) The tests conducted for a single excavation according to the requirements of paragraphs ~~(d)(3)(iii)(c)(3)(ii)~~ through ~~(vii)(v)~~ of this section count as one sample

under the sampling requirements of paragraphs ~~(d)(c)(3)(i)-(ii)~~ and ~~(viii)(vi)~~ of this section.

- (4) When this section is used to establish material properties for mainline pipeline components other than line pipe, the operator must develop and implement procedures for establishing and documenting any of the following: the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating. ANSI rating and material grade (to assure compatibility with pipe ends).
- (i) Materials in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, operator piping, or cross-connections with isolation valves from the mainline pipeline are not required to be tested for chemical and mechanical properties.
  - (ii) Verification of mainline material properties is required for non-line pipe components, including but not limited to, valves, flanges, fittings, fabricated assemblies, and other pressure retaining components appurtenances that are:
    - (A) Larger than 2-inch nominal diameter ~~and larger or~~
    - (B) Material grades greater than 42,000 psi (X-42), or
    - (C) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.
  - (iii) Procedures for establishing material properties for non-line pipe components where records are inadequate must be based upon documented manufacturing specifications. Where specifications are not known, usage of manufacturer's stamped or tagged material pressure ratings and material type may be used to establish pressure rating. The operator must document the basis of the material properties established using such procedures.
- (5) The material properties determined from the destructive or non-destructive tests required by this section cannot be used to raise the original grade or specification of the material, which must be based upon the applicable standard referenced in § 192.7.
- (6) If conditions make material verification by the above methods impracticable or if the operator chooses to use "other technology or another process" "new technology" ~~(alternative technical evaluation process plan), other than those described by this section~~, the operator must notify PHMSA at least ~~180~~ 90 days in advance of use in accordance with § 192.633, paragraph § 192.624(e) of this section. The operator

During the June 2017 GPAC meeting, PHMSA agreed to consider changing the threshold for non-line pipe components to larger than 2-inch nominal diameter. See comments of Mr. Nanney on pp. 162 of June 7 transcript.

Because of the diversity of processes and technologies that could be used to satisfy the objectives of 192.607, PHMSA should clarify that operators can submit notifications of the intent to use "other technology or another process."

Rather than refer to the "notifications" paragraph within the MAOP reconfirmation section, PHMSA should establish a separate "notifications" section in Subpart L for all of Part 192. The Associations propose § 192.633. See discussion in General Comments around single notifications sections.

~~must submit the alternative technical evaluation process plan to the Associate Administrator of Pipeline Safety with the notification and must obtain a “no objection letter” from the Associate Administrator of Pipeline Safety prior to usage of an alternative evaluation process.~~

Per Final December 2017 GPAC voting language: “Incorporate language stating that, if an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA of an alternative sampling approach, the operator can proceed with their method. PHMSA will notify the operator if additional review time is needed.”



§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or under §192.624, or the lowest of the following:

Per PHMSA March 26-28, 2018 GPAC Voting Slide 9 “PHMSA will consider moving 192.619(e) to be a subsection of 192.619(a) and will consider referencing section 192.624 in 192.619(a).”

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:

Per Mr. Nanney’s with PHMSA (3/27/18 Transcript, Page 267): “You can always say my MAOP is a number less than that established. If you establish it at 700 pounds, you can always establish it at a number less than that.”

(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, see §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

PHMSA should consider modifying the regulatory language in 192.619(a)(2) to capture Mr. Nanney’s comment. This will ensure consistency with how PHMSA and state agencies implement this rule to allow operators to establish MAOP at levels below pressure test established MAOP levels.

(ii) If the pipe is 12<sup>3</sup>/<sub>4</sub> inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) A pressure less than or equal to the pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors <sup>1</sup> , segment—			Converted under §192.14
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970) and before (Date of New Rule)	Installed after (Date of New Rule – 1 Day)	
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

<sup>1</sup>For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was updated according to the requirements in subpart K of this part:

PHMSA has announced that it will address issues pertaining to gas gathering pipelines in a separate GPAC meeting and final rule. Therefore, the new references to gas gathering pipelines in § 192.619 should not be modified in the transmission mandates rule. (See “Gas Rule Split-Out” presentation from Mr. Alan Mayberry, March 26, 2018.)

A process is currently underway to provide risk-based operating pressure determination requirements through the development of a consensus standard. This effort will consider the varying gathering line arrangements, such as segments can range from 50 feet to several miles in length, and provide a practical requirement that balances the need to ensure safe operation with the impact of this requirement.

Pipeline segment	Pressure date	Test date
<p>—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006 but before <i>(insert effective date of the rule)</i></p> <p><del>—Onshore gathering line that first became subject to this part (other than §192.612) on or after <i>(insert effective date of the rule)</i></del></p> <p>—Onshore transmission line that was a gathering line not subject to this part before March 15, 2006</p>	<p>March 15, 2006, or date line becomes subject to this part, whichever is later</p> <p><del><i>(Insert date that is one year after the effective date of the rule), or date line becomes subject to this part, whichever is later.</i></del></p> <p>March 15, 2006, or date line becomes subject to this part, whichever is later.</p>	5 years preceding applicable date in second column.
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

- (4) The pressure determined by the operator to be the maximum safe pressure after considering, material records, including material properties identified in accordance with §192.607, **if applicable**, and the history of the segment, particularly known corrosion and the actual operating pressure.
- (b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

Per PHMSA March GPAC Voting Slide 9 “Clarify that § 192.607 does not apply to distribution pipelines when determining MAOP by adding “if applicable” after the reference to § 192.607 in §192.619(a)(4).”

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).

(e) ~~Notwithstanding the requirements in paragraphs (a) through (d) above, onshore steel transmission pipelines that meet the criteria specified in § 192.624(a) must establish and document the maximum allowable operating pressure in accordance with § 192.624, using one or more of the following:~~

~~(1) Method 1: Pressure Test Pressure test in accordance with § 192.624(c)(1)(i) or spike hydrostatic pressure test in accordance with § 192.624(c)(1)(ii), as applicable;~~

~~(1) Method 2: Pressure Reduction Reduction in pipeline maximum allowable operating pressure in accordance with § 192.624(c)(2);~~

~~(2) Method 3: Engineering Critical Assessment Engineering assessment and analysis activities in accordance with § 192.624(c)(3);~~

~~(3) Method 4: Pipe Replacement Replacement of the pipeline segment in accordance with § 192.624(c)(4);~~

~~(4) Method 5: Pressure Reduction for Segments with Small PIR and Diameter Reduction of maximum allowable operating pressure and other preventive measures for pipeline segments with small PIRs and diameters, in accordance with § 192.624(c)(5); or~~

~~(5) Method 6: Alternative Technology Alternative procedure in accordance with § 192.624(c)(6).~~

(f) Operators of onshore steel gas transmission pipelines put into service after [insert effective date of rule] must maintain ~~all~~ records necessary to establish and document compliance with § 192.619(a), (b), (c), or (d), the MAOP of each pipeline as long as the pipe or pipeline remains in service. ~~Records that establish the pipeline MAOP, include, but are not limited to, design, construction, operation,~~

Per PHMSA March GPAC Voting Slide 9  
“PHMSA will consider moving 192.619(e) to be a subsection of 192.619(a) and will consider referencing section 192.624 in 192.619(a)”

As noted by Mr. Nanney of PHMSA during the March 26-28 March GPAC meeting, the intent of §192.619(e) was to create a linkage between §192.619 and §192.624 (3/27/18 Transcript, page 154). The Associations believe that referencing §192.624 in §192.619(a), as shown above, is the clearest way to accomplish the objective.

Per PHMSA March GPAC Voting Slide 10,  
“Clarify that the MAOP records requirements proposed in § 192.619(f) would apply only to onshore, steel, gas transmission pipelines.”

“Clarify the MAOP records requirements at § 192.619(f) only apply to records needed to demonstrate compliance with § 192.619(a) – (d). Move examples of MAOP documents to the preamble and guidance materials.”

“Clarify the MAOP records requirements proposed under section § 192.619 are not retroactive...

- Existing records on pre-existing P/L must be retained for P/L life.
- New pipelines must make and retain records for life of pipeline.
- MAOP records would be required for any pipeline placed in service after the effective date of the rule.”

~~maintenance, inspection, testing, material strength, pipe wall thickness, seam type, and other related data.~~ Records must be ~~reliable,~~ traceable, verifiable, and complete. ~~Existing records on pre-existing pipelines must be retained for pipeline life.~~ Available records used to establish maximum allowable operating pressure for pipelines put into service before *[insert effective date of rule]* should be retained for the lifetime of the pipeline segment.

§ 192.624 Maximum allowable operating pressure verification: Onshore steel transmission pipelines.

(a) **Applicable Locations.** The operator of an onshore steel transmission pipeline segment meeting any of the following conditions must establish the maximum allowable operating pressure using one or more of the methods specified in § 192.624(c)(1) through (6):

(1) ~~The pipeline segment has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction, installation, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations:~~

- ~~(i) A high consequence area as defined in § 192.903;~~
- ~~(ii) A class 3 or class 4 location; or~~
- ~~(iii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (i.e., "smart pigs").~~

~~(2) Pressure test records (1) Records~~ necessary to establish maximum allowable operating pressure ~~per subpart J for in accordance with 192.619(a)(2) or (c) for the date of construction of~~ the pipeline segment, including, but not limited to, records required by § 192.517(a), are not **reliable**, traceable, verifiable, and complete and the pipeline is **located** in one of the following **areas:** **locations:**

- (i) A high consequence area as defined in § 192.903; or
- (ii) A class 3 or class 4 location

~~(3) (2) The A~~ pipeline segment **that has** **a** maximum allowable operating

Per PHMSA March 26-28, 2018 GPAC Voting Slide 1: "Revise § 192.624(a) to strike paragraph (a)(1), which was the proposed criterion related to lines with previous reportable incidents due to crack defects."

Per PHMSA March 26-28, 2018 GPAC Voting slide 1: "Revise to refer to records required by § 192.619(a) and (c) instead of pressure test records required by Subpart J, as discussed by the committee, as shown below:

Pressure test Records necessary to establish maximum allowable operating pressure ~~per subpart J~~ in accordance with § 192.619(a)(2) or (c) at the time of construction for the pipeline segment ..."

Per PHMSA March 26-28, 2018 GPAC Voting slide 1: "Renumber § 192.624(a)(3) (for grandfathered lines) as paragraph (a)(2). Revise to apply only to lines with MAOP ≥ 30% SMYS.

Part 192 allows pipe segments in class 1 areas installed prior to 1970 to operate above 72% if their MAOP is established in accordance with § 192.619(c). These segments may still have a pressure test in accordance with § 192.619(a)(2). PHMSA should clarify that no further action is required if a pipeline segment has a TVC pressure test record in accordance with § 192.619(a)(2) for the date of construction. Otherwise, this will create a "do loop."

See March 26, 2018 GPAC Transcript Pages 107-108: Member Bradley: "I would say exactly what Andrew says, a valid pressure test in hand, the way I read this, and there's a lot here so I just want to unravel what I've heard, Steve, a valid pressure test in hand, you're done. You've got what you need, you can move forward. If you have to reconfirm and you've already got that valid pressure test, you're set. So when you reference 619(a), I sort of in my mind see the reference to 192.619(a)(2)." Mr. Nanney with PHMSA: "Yes, it is on the pressure test."

pressure that produces a hoop stress greater than or equal to 30 percent of specific minimum yield strength and was established in accordance with § 192.619(c) of this subpart before *[insert effective date of rule]* and does not have traceable, verifiable and complete records of a pressure test in accordance with 192.619(a)(2) for the date of construction and is ~~located~~ in one of the following ~~areas-locations~~:

- (i) A high consequence area as defined in § 192.903;
- (ii) A class 3 or class 4 location;  
or

- (iii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of free-swimming, commercially available instrumented in-line inspection tools (i.e. smart pigs) that can travel (using flow and pressure conditions encountered in normal operations) the length of the pipeline segment, inspect the entire circumference of the pipe, capture and record or transmit relevant, interpretable inspection data in sufficient detail for further evaluation of anomalies without permanent modifications to the pipe segment.

- (b) **Completion Date.** For pipelines installed before *[insert the effective date of rule]*, all actions required by this section must be completed according to the following schedule:

- (1) The operator must develop and document a plan for completion of all actions required by this section by *[insert date that is 1 year after the effective date of rule]*.
- (2) The operator must complete all actions required by this section on at least 50% of the mileage of locations that meet the conditions of § 192.624(a) by *[insert date that is 8 years after the effective date of rule]*.

Per the March 26-28, 2018 GPAC Voting Slide 15, PHMSA will “consider adding ‘free-swimming’ to the definition for ‘pipe segment can accommodate inspection by means of an instrumented in-line inspection tool’ per committee comments at the meeting.”

Per the presentation slides from the March 26-28 GPAC Meeting, PHMSA plans to include discussion in the preamble on the meaning of *Pipe segment can accommodate inspection by means of instrumented inline inspection tools*. PHMSA states that this means “a pipeline that can accommodate ... without any permanent physical modification of the pipeline.”

Industry asks that PHMSA consider:

- 1. Adding details regarding the meaning of “can accommodate inline inspection...” directly into § 192.624(a) and § 192.710(a), instead of providing guidance in the preamble. It is critically important that PHMSA’s intent is codified into regulation, as “can accommodate inline inspection...” greatly impacts the scope and impact of this rulemaking.
- 2. Industry asks that PHMSA consider including additional details, making it clear that not only does the pipeline have to be able to accommodate an in-line inspection device, but the device has to (1) be able to assess the pipeline fully and (2) traverse the pipeline under existing flow and pressure conditions.



- (3) The operator must complete all actions required by this section on 100% of the mileage ~~of locations~~ that meet the conditions of § 192.624(a) by *[insert date that is 15 years after the effective date of rule]* or as soon as practicable, but not to exceed 4 years, after the segment first meets the conditions of § 192.624(a), whichever is later.

- (4) If operational and environmental constraints limit the operator from meeting the deadlines in § 192.624 (b)(2) and (3) above, the operator may petition for an extension of the completion deadlines by up to one year, upon submittal of a notification to the Associate Administrator of the Office of Pipeline Safety in accordance with §192.635 paragraph (e) at least 90 days in advance of the deadlines in § 192.624. The notification must include an up-to-date plan for completing all actions in accordance with (b)(1), the reason for the requested extension, current status, proposed completion date, remediation activities outstanding, and any needed temporary safety measures to mitigate the impact on safety.

(c) **Maximum Allowable Operating Pressure**

Reconfirmation Determination. The operator of a pipeline segment meeting the criteria in paragraph

(a) above must reconfirm ~~establish~~ its maximum allowable operating pressure using one of the following methods:

(1) Method 1: Pressure test.

- (i) Perform a pressure test in accordance with Subpart J of this part 192.505(c). The maximum allowable operating pressure will be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii). An operator must verify material properties in accordance with 192.607 if information required for a pressure test is not documented in TVC records. The operator must use the best available information upon which the maximum allowable operating pressure is currently based to design the pressure test. If a pipeline segment does not have traceable, verifiable, and complete maximum allowable operating pressure records at the time of pressure test, the operator must opportunistically collect diameter, wall thickness and material grade data for the pipeline segment at

Per PHMSA March 26-28, 2018 GPAC Voting Slide 2: "Revise § 192.624(b) to address how the completion plan and completion dates required by § 192.624(b) would apply to pipelines...

The operator must complete all actions required by this section on 100% of the pipeline mileage ~~of locations~~ that meet the conditions of § 192.624(a) by *[insert date that is 15 years after the effective date of rule]* or as soon as practicable, but not to exceed 4 years after the segment first meets the conditions of § 192.624(a), whichever is later.

PHMSA will consider a waiver or no-objection procedure for extending the timeline past 4 years." The Associations believe this notification should be submitted in accordance the with Associations' proposed §192.635.

PHMSA should clarify that 192.624 outlines a process for *reconfirming* MAOP, not *determining* MAOP. All pipeline segments in operation have a current MAOP.

Per PHMSA March 26-28, 2018 GPAC Voting Slide 3:

"In § 192.624(c)(1), refer to Subpart J instead of § 192.505(c)"

"... if the pressure test segment does not have TVC MAOP records, use the best available information (upon which the MAOP is currently based). Create a requirement for an operator to add the test segment to its plan for opportunistically....192.607"

excavations associated with the pressure test in accordance with §192.607.

- ~~(ii) If the pipeline segment includes legacy pipe or was constructed using legacy construction techniques or the pipeline has experienced an incident, as defined by § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking, then the operator must perform a spike pressure test in accordance with § 192.506. The maximum allowable operating pressure will be equal to the test pressure specified in § 192.506(c) divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).~~

Per PHMSA March 26-28, 2018 GPAC Voting Slide 3: "For Method 1 (pressure test): Delete paragraphs (ii) and (iii) to remove spike testing for lines with suspected crack defects."

- ~~(iii) If the operator has reason to believe any pipeline segment may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph (d) of this section.~~

- (2) Method 2: Pressure Reduction - The pipeline maximum allowable operating pressure will be no greater than the highest actual operating pressure sustained by the pipeline from December 17, 2004 during the 18 months 5 years preceding [insert effective date of rule] divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest pressure value for the entire segment or using the operating pressure gradient (i.e., the location-specific operating pressure at each location).

If an operator has reduced a pipeline's MAOP during the time period since the implementation of the Gas Pipeline Integrity Management Regulation (Subpart O) on December 17, 2004 (e.g., for voluntary reasons, due to a class location change, etc.), then the reduction in MAOP should be considered as a Pressure Reduction in the new MAOP as determined under §192.624(c)(2) Method 2. In many instances, further reductions are not even possible if the pipeline is to continue serving its existing load.

- (i) Where the pipeline segment has had a class location change in accordance with § 192.611 and pipe material and pressure test records are not available, the operator must reduce the pipeline segment MAOP as follows:

Per PHMSA March 26-28, 2018 GPAC Voting Slide 4: "For Method 2 (pressure reduction): Increase the look-back period from 18 months to five (5) years."

- (A) For segments where a class location changed from 1 to 2, from 2 to 3, or from 3 to 4, reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline from December 17, 2004 during the 18 months 5 years preceding [insert effective date of rule] divided by 1.39 for class 1 to 2, 1.67 for class 2 to 3, and 2.00 for class 3 to 4.



- (B) For segments where a class location changed from 1 to 3, reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline ~~from December 17, 2004 during the 18 months 5 years preceding [insert effective date of rule]~~ divided by 2.00.

~~(ii) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph (d) of this section.~~

Per PHMSA March 26-28, 2018  
GPAC Voting Slide 4: "Strike the requirement in § 192.624(c)(2)(ii) to perform fracture mechanics analysis on segments that confirm MAOP via Method 2 (Pressure Reduction)."

~~(iii) Future uprating of the segment in accordance with subpart K is allowed if the maximum allowable operating pressure is established using Method 2.~~

- (ii) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor, the operator must notify PHMSA in accordance with § 192.633 paragraph (e) of this section no later than seven calendar days after establishing the reduced maximum allowable operating pressure. The notification must include the following details:

The reference to subpart K and uprating here is unnecessary. There is nothing in 192.624 that suggests operators would not be able to in the future. By providing this reference in some, but not all, of the MAOP Verification methods, the regulations could be interpreted that uprating pursuant to Subpart K may not be a future option for some pipes.

- (A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in § 192.624(c)(2);
- (B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with §192.712 paragraph (d) of this section;
- (C) Justification that establishing maximum allowable operating pressure by another method allowed by this section is impractical;
- (D) Justification that the reduced maximum allowable operating pressure determined by the operator is safe based on analysis of the condition of the pipeline segment, including material records, material properties verified in accordance § 192.607, and the history of the segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned.
- (E) Planned duration for operating at the requested maximum allowable operating pressure, long term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis per §192.712. and other validated forms of engineering analysis that have been

Per PHMSA March 26-28, 2018  
GPAC Voting Slide 4:  
"§192.624(d) Fracture mechanics analysis for failure stress and crack growth analysis and move fracture mechanics to a new stand-alone section § 192.712."

~~reviewed and confirmed by subject matter experts in metallurgy and fracture mechanics.~~

- (3) Method 3: Engineering Critical Assessment - Conduct an engineering critical assessment and analysis (ECA) to establish the material strength condition of the segment and maximum allowable operating pressure. An ECA is an analytical procedure, based on assessment information, fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), and operating history, ~~operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections. The ECA must assess: threats; loadings and operational circumstances relevant to those threats including along the right of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; initial and final defect size relevance. The ECA must quantify the coupled effects of any defect in the pipeline.~~

- (i) *ECA analysis.*

- (A) ~~The ECA must integrate and analyze the results of the material documentation program required by §192.607, if applicable, and the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including but not limited to close interval surveys, coating surveys, and interference surveys required by subpart I, root cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by § 192.710 and subpart O.~~

PHMSA should consider removing the aspects of the proposed ECA that address the long-term management of various integrity threats. The goal of the ECA method is to confirm material strength, like a pressure test. Method 3 should be an ILI-based methodology focused on assessing manufacturing and construction-related features to confirm material strength.

The ECA method is composed of several analyses to confirm material strength, as outlined below. Different material properties are critical for each analysis method, as discussed above. Therefore, for clarity, PHMSA should list the material attributes needed for each analysis below, where each analysis is described. See recommended language in (A) and (B) below.

The ECA process should be focused on a one-time assessment of current manufacturing and construction features, as identified by inline inspection, that could affect material strength. The reference to other defects “that could remain in the pipe” is confusing and unnecessary if an operator has run an ILI tool to identify cracks and crack-like defects currently in the pipe.

(A) ~~(B)~~ The ECA must analyze any cracks or crack-like manufacturing and construction defects remaining in the pipe that are cracks or crack-like, or that could remain in the pipe, to determine the predicted failure pressure (PFP) of each injurious defect in accordance with §192.712. each defect. The ECA must use the techniques and procedures in Battelle Final Reports (“Battelle’s Experience with ERW and Flash Weld Seam Failures: Causes and Implications” Task 1.4), Report No. 13-002 (“Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams” Subtask 2.4), Report No. 13-021 (“Predicting Times to Failure for ERW Seam Defects that Grow by Pressure Cycle-Induced Fatigue” Subtask 2.5) and (“Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures Phase 1” Task 4.5) (incorporated by reference, see § 192.7) or other technically proven methods including but not limited to API RP 579-1/ASME FFS-1, June 15, 2007, (API 579-1, Second Edition) Level II or Level III, CorLas™, or PAFFC. The ECA must use conservative assumptions for crack dimensions (length and depth) and failure mode (ductile, brittle, or both) for the microstructure, location, type of defect, and operating conditions (which includes pressure cycling). If diameter or wall thickness is not known or not documented by traceable, verifiable, and complete records, then the operator must verify these properties using the material documentation process specified in §192.607. If SMYS or actual material yield is not known or not documented traceable, verifiable, and complete records, then the operator must verify these properties using the material documentation process specified in §192.607 or assume grade A pipe (30 ksi). If actual material toughness is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must:

Per PHMSA March 26-28, 2018 GPAC Voting Slide 5: “PHMSA suggests revising §192.624(c)(3)(i)(B) to read as follows: (B) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure (PFP) of each injurious defect in accordance with § 192.712.”

Per PHMSA March 26-28, 2018 GPAC Voting Slide 5: “Add requirement to verify material properties in accordance with §192.607 if information needed for a successful ECA is not documented in TVC records...”

- (1) Use Charpy energy values from similar vintage pipe until properties are obtained through opportunistic testing;
- (2) Verify the determine-a Charpy v-notch toughness based upon the material documentation process program specified in § 192.607;
- (3) uUse conservative values for Charpy v-notch toughness as follows: body toughness of less than or equal to 13 5.0 ft-lb and seam toughness of less than or equal to 4 1 ft-lb. If the pipe segment has a history of leaks or failures due to cracks, use conservative Charpy energy values of 5 ft-lb for pipe body and 1 ft-lb for pipe seam; or

- (4) Use other appropriate values based on technology or technical publications that an operator demonstrates can provide conservative Charpy energy values of the crack-related conditions of the line pipe, with notification to PHMSA in accordance with § 192.633.

Per PHMSA March 26-28, 2018 GPAC Voting Slide 6: "Clarifying that use of differing default Charpy values may be requested by a 90-day notification to PHMSA."

- (B) ~~(C)~~ The ECA must analyze any metal loss defects not associated with a dent including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe to determine the predicted failure pressure (PFP). ASME/ANSI B31G (incorporated by reference, see § 192.7) or AGA Pipeline Research Committee Project PR-3-805 ("RSTRENG," incorporated by reference, see § 192.7) must be used for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth). When determining PFP for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used. If diameter or wall thickness is not known or not documented by traceable, verifiable, and complete records, then the operator must verify these properties using the material documentation process specified in §192.607. If SMYS or actual material yield ~~and ultimate tensile strength~~ is not known or not ~~adequately~~ documented by ~~reliable~~, traceable, verifiable, and complete records, then the operator must assume grade A (30 ksi) pipe or verify these determine the material properties based upon the material documentation process program specified in § 192.607.
- (C) ~~(D)~~ The ECA must analyze interacting defects to conservatively determine the most limiting PFP for interacting defects. Examples include but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.
- (D) ~~(E)~~ The maximum allowable operating pressure must be established by dividing at the lowest PFP for any known or postulated defect, or interacting defects, remaining in the pipe ~~divided~~ by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

Per PHMSA Dec. GPAC Voting Slide 97: "PHMSA: in IVP, operators may assume Grade A (30,000 psi or lower) if pipe grade is unknown for purposes of establishing MAOP."

The references to ultimate tensile strength for ECA calculations is inappropriate. Ultimate tensile strength is not required to analyze either metal loss or cracking/crack-like defects.

PHMSA should remove the "use of prior pressure test" alternative within the ECA. This allows the ECA process to be simplified and focused on a one-time assessment of current features, as identified by inline inspection, that could affect material strength. Method 1 already provides a pressure test method for reconfirming MAOP.

~~(ii) Use of prior pressure test. If pressure test records as described in subpart J and § 192.624(c)(1) exist for the segment, then an in line inspection program is not required, provided that the remaining life of the most severe defects that could have survived the pressure test have been calculated, and a re-assessment interval has been established. The appropriate retest interval and periodic tests for time dependent threats must be determined in accordance with the methodology in § 192.624(d) Fracture mechanics modeling for failure stress and crack growth analysis.~~

(ii) ~~(iii) In-line inspection. If the segment does not have records for a pressure test in accordance with subpart J test levels and § 192.624(c)(1),~~ The operator must develop and implement an

inline inspection (ILI) program using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects including cracking and ~~selective seam weld corrosion~~, longitudinal, circumferential and girth weld cracks, hard spot cracking, and ~~stress corrosion cracking~~. At a minimum, the operator must conduct an assessment using a high resolution magnetic flux leakage (MFL) tool, a high resolution deformation tool, and one or more of the following: ~~either~~ an electromagnetic acoustic transducer (EMAT), circumferential MFL (CMFL), helical MFL/spiral field (SMFL), or ultrasonic testing (UT) tool.

References to SSWC and SCC, which are time-dependent features, should be removed. These features are more appropriately managed as part of ongoing corrosion control, maintenance, anomaly response, and integrity management programs. MAOP reconfirmation is intended to identify manufacturing and construction features that may impact material strength, not time-dependent features.

Additionally, Circumferential MFL (CMFL) or helical MFL/spiral field (SMFL) should also be allowed as an ILI method for identifying manufacturing features. Operators have had success using CMFL/SMFL for this purpose, similar to EMAT or UT.

(A) In lieu of the ~~technologies and processes tools~~ specified in paragraph § 192.624(c)(3)(i), an operator may use “other technology or another process” if it is validated by a subject matter expert in metallurgy and fracture mechanics to produce an equivalent understanding of the condition of the pipe. If an operator elects to use “other technology or another process,” it must notify the Associate Administrator of Pipeline Safety, at least ~~90~~ 180 days prior to use, in accordance with § 192.633 paragraph (e) of this section, and receive a “no objection letter” from the Associate Administrator of Pipeline Safety prior to its usage. The “other technology” notification must have:

- (1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments including characterization of defect size crack assessments (length, depth, and volumetric); and
- (2) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and remediate defects discovered.

(B) ~~If the operator has information that indicates a pipeline includes segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.~~

The integrity concern related to hard spots is that hard spots can result in cracking on in-service pipelines. The proposed ECA process already requires operators to assess for cracks. Identifying hard spots to anticipate future cracking may be a maintenance and integrity management concern, but is not appropriate as part of one-time MAOP reconfirmation.

(C) ~~If the pipeline has had a reportable incident, as defined in § 192.3, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with paragraph § 192.624(c)(3)(iii) includes an engineering evaluation program to analyze the susceptibility of girth weld failure due to lateral stresses.~~

As discussed above, pipeline reportable incidents should be addressed as part of corrosion control, operations, maintenance, integrity management, and anomaly response, but do not invalidate MAOP for the entire segment or pipeline.

(D) ~~Inline inspection must be performed in accordance with § 192.493.~~

The Associations believe the addition of §192.493 falls outside of the scope of the Congressional Mandates and therefore should not be included in the transmission mandates rule.

(B) ~~(E) The operator must use unity plots or equivalent methodologies to demonstrate the effectiveness of the inline inspection tools in identifying and sizing actionable manufacturing and construction-related anomalies. All MFL and deformation tools used must have been validated to characterize the size of defects within 10% of the actual dimensions with 90% confidence. All EMAT or UT tools must have been validated to characterize the size of cracks, both length and depth, within 20% of the actual dimensions with 80% confidence, with like similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated.~~

Per PHMSA March 26-28, 2018 GPAC Voting slide 4: "Remove ILI tool performance specifications and replace with requirement to verify tool performance using unity plots or equivalent technologies."

(C) ~~(F) Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and subpart O, and Operators must develop procedures to~~ conservatively

The reference to integrity management and anomaly response sections for interpreting and evaluating assessment results in proposed 192.624(c)(3)(iii)(F) is confusing and unnecessary; requirements for analyzing manufacturing and construction features identified through the ECA ILI are sufficiently addressed in 192.624(c)(3).

Furthermore, because PHMSA is not proposing to codify new anomaly response and repair criteria in the transmission mandates rule, PHMSA should remove the references to specific repair criteria sections.

Also, ILI tool performance verification is addressed above and should not be duplicated in (F).

account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions ~~by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards confirmed for accuracy through confirmation~~



~~tests for the type defects and pipe material vintage being evaluated.~~ Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.

(D) Anomalies detected by ILI assessments must be repaired in accordance with applicable repair criteria. ~~in §§ 192.713 and 192.933~~

- (iv) ~~If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.624(d).~~

Per PHMSA March 26-28, 2018 GPAC Voting Slide 4: "PHMSA suggests revising § 192.624(c)(3)(i)(B) to read as follows: (B) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure (PFP) of each injurious defect in accordance with § 192.712." Therefore, proposed 192.624(c)(3)(iv) should be removed, as it is duplicative and confusing.

(2) Method 4: Pipe Replacement - Replace the pipeline segment.

(3) Method 5: Pressure Reduction for Segments with Small Potential Impact Radius and Diameter – Pipelines with ~~a maximum allowable operating pressure less than 30 percent of specified minimum yield strength,~~ a potential impact radius (PIR) less than or equal to 150 feet, ~~nominal diameter equal to or less than 8 inches, and which cannot be assessed using inline inspection or pressure test,~~ may establish the maximum allowable operating pressure as follows:

Per PHMSA March 26-28, 2018 GPAC Voting Slide 7: "For Method 5...Delete the size and pressure criteria. The applicability would be based solely on a PIR of ≤ 150 feet."

- (iv) Reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline ~~from December 17, 2004 during the 18 5 years months preceding [insert effective date of rule]~~ divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of eight hours during one continuous 30-day period. The reduced maximum allowable operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire segment or the operating pressure gradient (i.e., the location specific operating pressure at each location);
- ~~(v) Conduct external corrosion direct assessment in accordance with § 192.925, and internal corrosion direct assessment in accordance with § 192.927;~~

- ~~(vi) Develop and implement procedures for conducting non-destructive tests, examinations, and assessments for cracks and crack-like defects, including but not limited to stress-corrosion cracking, selective seam weld corrosion, girth weld cracks, and seam defects, for pipe at all excavations associated with anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, or any other reason for which the pipe segment is exposed, except for segments exposed during excavation activities that are in compliance with § 192.614;~~
- (vii) Conduct quarterly monthly patrols in Class 1 and 2 locations, at an interval not to exceed 45 days; weekly patrols in Class 3 locations not to exceed 10 days; and semi-weekly patrols in Class 4 locations, at an interval not to exceed 120 days six days, and bi-monthly patrols in Class 3 and 4 locations, at an interval not to exceed 90 days, and in accordance with § 192.705;
- (viii) Conduct quarterly monthly, instrumented leakage surveys in Class 1 and 2 locations, at intervals not to exceed 45 days; weekly leakage surveys in Class 3 locations at intervals not to exceed 10 days; and semi-weekly leakage surveys in Class 4 locations, at intervals not to exceed 120 days six days, and bi-monthly patrols in Class 3 and 4 locations, at an interval not to exceed 90 days, in accordance with § 192.706; and
- ~~(ix) Odorize gas transported in the segment, in accordance with § 192.625;~~
- ~~(x) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with § 192.712. paragraph § 192.624(d).~~
- ~~(xi) Under Method 5, future uprating of the segment in accordance with subpart K is allowed.~~
- (4) Method 6: Other Alternative Technology or Process- Operators may use other technology or another an alternative technical evaluation process that provides a sound engineering basis for verifying establishing maximum allowable operating pressure. If an operator elects to use alternative other technology or another process, the operator must notify PHMSA at least 90 180 days in advance of use in accordance with § 192.633. paragraph § 192.624(e) of this section. The operator must submit the alternative technical evaluation to PHMSA with the notification, and obtain a “no objection letter” from the Associate Administrator of Pipeline Safety prior to usage of alternative technology. The notification must include the following details:
- (iv) Descriptions of the technology or technologies to be used for tests, examinations, and assessments, establishment of material properties, and analytical techniques, with like-

Per PHMSA March 26-28, 2018  
GPAC Voting Slide 7: “Change  
frequency of patrols and surveys:

In class 1 and 2 locations to 4 times  
per year.

In class 3 and 4 locations to 6 times  
per year.”

Per PHMSA March 26-28, 2018 GPAC Voting  
Slide 7: “For Method 5...Strike ECDA, Crack  
Analysis Program, odorization, and fracture  
mechanics analysis requirements.”

Per PHMSA March 26-28,  
2018 GPAC Voting Slide  
7: “For Method 6, Other  
Technology:

Use same 90-day ‘no  
objection’ letter language  
the committee approved  
for 192.607.”



similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated.

- (v) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered;

~~(vi) Methodology and criteria used to determine reassessment period or need for a reassessment including references to applicable regulations from this Part and industry standards;~~

~~(vii) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;~~

~~(viii) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of PFP quantified as a fraction of specified minimum yield strength;~~

~~(ix) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.624(d);~~

~~(x) Remediation methods with proven technical practice;~~

~~(xi) Schedules for assessments and remediation;~~

~~(xii) Operational monitoring procedures;~~

(xiii) Methodology and criteria used to justify and establish the maximum allowable operating pressure; and

(xiv) Documentation requirements for the operator's process, including records to be generated.

~~(d) Fracture mechanics modeling for failure stress and crack growth analysis.~~

~~(d) Notifications. An operator must submit all notifications required by this section to the Associate Administrator for Pipeline Safety, by:~~

- (1) ~~Sending the notification to the Office of Pipeline Safety, Pipeline and Hazardous Material Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE, Washington, DC 20590-0001;~~

As proposed, the list of details to be included in the Method 6 notification is unclear, excessive, and duplicative. The goal of Method 6 is to confirm material strength, similar to a pressure test but using an alternative technology or process. Therefore, PHMSA should remove the aspects related to the long-term management of various integrity threats. Detailed descriptions of the alternative technology/process, detailed procedures for tests and assessments, a discussion of criteria for establishing MAOP, and documentation requirements provide ample information for PHMSA to determine whether it has an objection to an operator's

Per PHMSA March GPAC Voting Slide 4, "§192.624(d) Fracture mechanics analysis for failure stress and crack growth analysis and move fracture mechanics to a new stand-alone section § 192.712."

Rather than refer to the "notifications" paragraph within the MAOP reconfirmation section, PHMSA should establish a separate "notifications" section in Subpart L for all of Part 192. The Associations propose §§ 192.633 and 192.635. See discussion in General Comments around single notifications sections.

- (2) ~~Sending the notification to the Information Resources Manager by facsimile to (202) 366-7128; or~~
- (3) ~~Sending the notification to the Information Resources Manager by e-mail to InformationResourcesManager@dot.gov.~~
- (4) ~~An operator must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.~~
- (d) ~~(f)~~ **Records.** Each operator must keep for the life of the pipeline ~~reliable~~, traceable, verifiable, and complete records of the investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions made in accordance with the requirements of this section after (insert effective date of the rule).

Adding a reference to the effective date in proposed 192.624(f) would help clarify that this is a prospective requirement to retain records of the work completed in executing this part.

§ 192.633 Other Technology or Process Notification

When allowed in this part, if an operator chooses to use other technology or another process, the operator must notify PHMSA, in accordance with § 192.635. The notification must occur at least 90 days in advance of use and the operator must submit a description of the technology or process to the Associate Administrator of Pipeline Safety with the notification. If an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA, the operator can proceed with the other technology or process. PHMSA will notify the operator within 90 days of the notification if additional review time is needed.'

§ 192.635 How does an operator notify PHMSA?

- (a) An operator must submit all notifications required by this section to the Associate Administrator for Pipeline Safety, by:
- (1) Sending the notification to the Office of Pipeline Safety, Pipeline and Hazardous Material Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE, Washington, DC 20590-0001;
  - (2) Sending the notification to the Information Resources Manager by facsimile to (202) 366-7128; or
  - (3) Sending the notification to the Information Resources Manager by e-mail to [InformationResourcesManager@dot.gov](mailto:InformationResourcesManager@dot.gov).
  - (4) An operator must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

## **Subpart M – Maintenance**

### **§ 192.710 Pipeline assessments.**

#### **(a) Applicability**

- (1) This section applies to onshore transmission pipeline segments that **have a maximum allowable operating pressure that produces a hoop stress greater than or equal to 30 percent of specific minimum yield strength and** are located in:

- (i) A class 3 or class 4 location; or
- (ii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of **free-swimming, commercially available** instrumented in-line inspection tools (i.e. smart pigs) **that can travel (using flow and pressure conditions encountered in normal operations) the length of the pipeline segment, inspect the entire circumference of the pipe, capture and record or transmit relevant, interpretable inspection data in sufficient detail for further evaluation of anomalies without permanent modifications to the pipe segment.**

- (2) This section does not apply to a pipeline segment located in a High Consequence Area as defined in § 192.903.

#### **(b) General.**

- (1) An operator must perform initial assessments in accordance with this section no later than **[insert date that is 15 14 years after the effective date of the rule]** and periodic reassessments every **20 10** years thereafter, or a shorter reassessment interval based upon the type anomaly, operational, material, and environmental conditions found on the pipeline segment, or as otherwise necessary to ensure public safety.

Per the March 2, 2018 GPAC Voting Slide 5, PHMSA will “revise proposed §192.710(a) to apply to lines with MAOP ≥ 30% SMYS.”

Per the March 26-28, 2018 GPAC Voting Slide 15, PHMSA will “consider adding ‘free-swimming’ to the definition for ‘pipe segment can accommodate inspection by means of an instrumented in-line inspection tool’ per committee comments at the meeting.”

Per the presentation slides from the March 26-28 GPAC Meeting. PHMSA plans to include discussion in the preamble on the meaning of *Pipe segment can accommodate inspection by means of instrumented inline inspection tools*. PHMSA states that this means “a pipeline that can accommodate ... without any permanent physical modification of the pipeline.”

Industry asks that PHMSA consider:

1. Adding details regarding the meaning of “can accommodate inline inspection...” directly into § 192.624(a) and § 192.710(a), instead of providing guidance in the preamble. It is critically important that PHMSA’s intent is codified into regulation.
2. Industry asks that PHMSA consider including additional details, making it clear that not only does the pipeline have to be able to accommodate an in-line inspection device, but the device has to (1) be able to assess the pipeline fully and (2) traverse the pipeline under existing flow and pressure conditions.

Per the March 2, 2018 GPAC Voting Slide 5, PHMSA will “revise the initial assessment and reassessment intervals from 15/20 years to 14/10 years based on a risk assessment.”

- (2) *Prior assessment.* An operator may use a prior assessment conducted before ***[Insert effective date of the final rule]*** as an initial assessment for the segment if the assessment ~~met meets~~ the Subpart O requirements for in-line inspection at the time of the assessment. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (b)(1) of this section.
- (3) *MAOP verification.* An operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.
- (c) *Assessment Method.* The initial assessments and the reassessments required by paragraph (b) must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline is susceptible and must be performed using one or more of the following methods:
- (1) Internal inspection tool or tools capable of detecting ~~corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots, and any other~~ threats to which the segment is susceptible, as determined by the operator. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493;
  - (2) Pressure test conducted in accordance with subpart J of this part. ~~The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, manufacturing and related defect threats, including defective pipe and pipe seams, dents and other forms of mechanical damage;~~
  - (3) “Spike” hydrostatic pressure test in accordance with § 192.506;
  - (4) Excavation and *in situ* direct examination by means of visual examination and direct measurement and recorded non-destructive examination results ~~and data needed to assess all threats~~, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI);
  - (5) Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F;

Since PHMSA proposes to modify the Subpart O assessment requirements, it’s important to reference the “Subpart O requirements for in-line inspection at the time of assessment.”

Although not explicitly voted by the GPAC, the Associations believe PHMSA should make the same changes in §192.710 as the GPAC endorsed for §192.921. It’s critical that assessment requirements are consistent inside and outside of HCAs.

Per the March 2, 2018 GPAC Vote Slide 2, PHMSA will “revise the language in proposed 192.921(a)(1) to clarify that operators select assessment methods based upon the threats to which the pipeline is susceptible ...”

The Associations believe the addition of §192.493 falls outside of the scope of the Congressional Mandates and therefore should not be included in the transmission mandates rule.

- (6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. ~~Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess (due to low operating pressures and flows, lack of inspection technology, and critical delivery areas such as hospitals and nursing homes) using the methods specified in paragraphs (d)(1) through (d)(5) of this section.~~ An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 or 192.929; or

Per the March 2, 2018 GPAC Voting Slide 5, PHMSA will “clarify §192.710(c)(6) by stating that direct assessment may be used only if appropriate for the threat being assessment but cannot be used to assess threats for which direct assessment is not suitable.”

The Associations believe that the language within §192.710(c)(6) “to address threats of external corrosion, internal corrosion and stress corrosion cracking” effectively and efficiently meets the GPAC’s guidance without unnecessary regulatory text that may add confusion or uncertainty.

- (7) Other technology or technologies that an operator demonstrates can provide an equivalent understanding of the line pipe for each of the threats to which the pipeline is susceptible.

- ~~(8) For segments with MAOP less than 30% of the SMYS, an operator must assess for the threats of external and internal corrosion, as follows:~~

Per the March 2, 2018 GPAC Voting Slide 5, PHMSA will “remove proposed §192.710(c)(8) dealing with low-stress assessments.”

- ~~(i) External corrosion. An operator must take one of the following actions to address external corrosion on a low-stress segment:~~

~~(A) Cathodically protected pipe. To address the threat of external corrosion on cathodically protected pipe, an operator must perform an indirect assessment (i.e. indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) at least every seven years on the segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.~~

~~(B) Unprotected pipe or cathodically protected pipe where indirect assessments are impractical. To address the threat of external corrosion on unprotected pipe or cathodically protected pipe where indirect assessments are impractical, an operator must—~~

~~(1) Conduct leakage surveys as required by § 192.706 at 4-month intervals; and~~

~~(2) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.~~

- ~~(ii) Internal corrosion. To address the threat of internal corrosion on a low stress segment, an operator must—~~

~~(A) Conduct a gas analysis for corrosive agents at least twice each calendar year;~~

~~(B) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a segment; and~~

~~(C) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (ii)(A) (ii)(B) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.~~

- (d) *Data analysis.* A person qualified by knowledge, training, and experience must analyze the data obtained from an assessment performed under paragraph (b) of this section to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing anomalies.
- (e) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information to determine that a condition exists. An operator must promptly, but no later than ~~240~~ **180** days after an assessment, obtain sufficient information about a condition to make the determination required under paragraph (d), unless the operator can demonstrate that that ~~240~~ **180** -days is impracticable.
- (f) *Remediation.* An operator must comply with the requirements in [§ 192.711](#) and [§ 192.713](#) if a condition that could adversely affect the safe operation of a pipeline is discovered.
- (g) *Consideration of information.* An operator must consider all available information about a pipeline in complying with the requirements in paragraphs (a) through (f).

Per the March 2, 2018 GPAC Voting Slide 5, PHMSA will “change discovery period for non-HCAs from 180 to 240 days.”

Because PHMSA is not proposing to codify new anomaly response and repair criteria in § 192.713 in the transmission mandates rule, the Associations suggest that PHMSA reference existing §192.711 and §192.713 for anomaly remediation on transmission pipelines outside of HCAs. Current §192.711 addresses temporary and permanent response timing and §192.713 addresses repair methods. When §192.713 is revised in the second rule, PHMSA can revise §192.710(f) to refer only to §192.713.

## § 192.711 Transmission lines: General requirements for repair Procedures

- (a) *Temporary repairs.* Each operator must take immediate temporary measures to protect the public whenever:
- (1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and
  - (2) It is not feasible to make a permanent repair at the time of discovery.
- (b) *Permanent repairs.* An operator must make permanent repairs on its pipeline system according to the following:
- (1) Non integrity management repairs: The operator must make permanent repairs as soon as feasible.
  - (2) Integrity management repairs: When an operator discovers a condition on a pipeline covered under Subpart O-Gas Transmission Pipeline Integrity Management, the operator must remediate the condition as prescribed by §192.933(d).
- (c) *Welded patch.* Except as provided in §192.717(b)(3), no operator may use a welded patch as means of repair.

Changes to §192.711 fall outside the scope of the initial rulemaking. Therefore, the Associations propose that PHMSA maintain existing requirements in §192.711.



§ 192.712 Fracture mechanics modeling for failure stress and crack growth analysis

- (a) Applicability. Operators must use the process described in this section where fracture mechanics modeling is required by this part.
- (b) Fracture Mechanics Modeling for Failure Stress Pressure. Failure stress pressure must be determined using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other). Examples of technically proven models include but are not limited to: for the brittle failure mode, the Raju/Newman Model; for the ductile failure mode, Modified LnSec, API RP 579-1/ASME FFS-1, June 15, 2007, (API 579-1, Second Edition) – Level II or Level III, CorLas™, and PAFFC (incorporated by reference, see § 192.7). The analysis must account for model inaccuracies and tolerances and use conservative assumptions for crack dimensions (length and depth) and failure mode (ductile, brittle, or both) for the microstructure, location, and type of defect.
- (1) If pipe diameter or wall thickness is not known or records are not available, the operator must:
- (i) Use the same diameter and/or wall thickness values that are the basis for the current MAOP; or
  - (ii) Verify material properties based upon the material documentation process specified in § 192.607.
- (2) If actual material toughness is not known or records are not available, the operator must:
- (i) Use Charpy energy values from similar vintage pipe until properties are obtained through opportunistic testing;
  - (ii) Verify Charpy energy values based upon the material documentation process specified in § 192.607;

Per PHMSA March 26-28, 2018 GPAC Voting Slide 4: “§ 192.624(d) Fracture mechanics analysis for failure stress and crack growth analysis and move fracture mechanics to a new stand-alone section § 192.712.”

Per PHMSA March GPAC Voting Slide 6:

“Revise the fracture mechanics requirements by:

- Striking sensitivity analysis requirements and replacing with requirement that operators account for model inaccuracies and tolerances.
- Striking references to § 192.624 [MAOP reconfirmation].
- Striking references to § 192.506 [spike pressure test].

Per PHMSA March 27<sup>th</sup> GPAC Voting Slide 6

“Operators can use a conservative Charpy energy value based on the sampling requirement at § 192.607.”

“Operators can use Charpy values from similar / the same vintage pipe, until properties are obtained through an opportunistic testing program”

“Clarifying the default Charpy values of 13 ft-lb (body) and 4 ft-lb (seam) only apply to pipe with suspected low-toughness properties or unknown toughness properties.”

“If a pipe segment has a history of leaks or failures due to cracks... use Charpy values of 5 ft-lb (body) and 1 ft-lb (seam).”

- (iii) Use conservative Charpy energy values of 13.0 ft-lb for pipe body and 4.0 ft-lb for pipe seams. If pipe segment has a history of leaks or failures due to cracks, use default Charpy energy values of 5 ft-lb for pipe body and 1 ft-lb for pipe seam; or
  - (iv) Use other appropriate values based on technology or technical publications that an operator demonstrates can provide conservative Charpy energy values of the crack-related conditions of the line pipe, with notification to PHMSA in accordance with § 192.633.
- Per PHMSA March 26-28, 2018 GPAC Voting Slide 6: “Clarifying that use of differing default Charpy values may be requested by a 90-day notification to PHMSA.”
- (3) If SMYS or actual material yield is not known or records are not available, the operator must
    - (i) Use the same material properties that are the basis for the current MAOP;
    - (ii) Verify these properties using the material documentation process specified in § 192.607; or
    - (iii) Assume grade A pipe (30 ksi).
  - (c) Analysis for Flaw Growth and Remaining Life. If the operator determines that the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, such as stress corrosion cracking, an appropriate engineering analysis methodology must be used. The above methodologies should account for model inaccuracies and tolerances and be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure.
    - (1) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).
    - (2) For cases dealing with an estimation of the defect sizes that would survive a hydro test pressure, if actual material toughness is not known or records are not available, the operator must:
      - (i) Use Charpy energy values from similar vintage pipe until properties are obtained through opportunistic testing;
      - (ii) Verify Charpy energy values based upon the material documentation process specified in § 192.607;
      - (iii) Use a full size equivalent Charpy upper-shelf energy level of 120 ft-lb; or
      - (iv) Use other appropriate values based on technology or technical publications that an operator demonstrates can provide conservative Charpy energy values of the crack-related conditions of the line pipe, with notification to PHMSA in accordance with § 192.633.
    - (3) For subsequent critical flaw size calculations at MAOP of flaws that would survive a hydro test, the same Charpy energy value established in (2) may be used.
    - (4) The operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.

- (d) Review. Analyses conducted in accordance with this paragraph must be reviewed and confirmed by a subject matter expert.
- (e) Records. Each operator must keep for the life of the pipeline records of the analyses made in accordance with the requirements of this section after [insert effective date of the rule].

Per PHMSA March 26-28, 2018 GPAC  
Voting Slide 6: "Adding a paragraph  
to require records be retained."

**§192.713 Transmission lines: Permanent field repair of imperfections and damages**

- (a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—
  - (1) Removed by cutting out and replacing a cylindrical piece of pipe; or
  - (2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.
- (b) Operating pressure must be at a safe level during repair operations.

Changes to §192.713 fall outside the scope of the initial rulemaking. Therefore, the Associations propose that PHMSA maintain existing requirements in §192.713.

## **Subpart O – Gas Transmission Pipeline Integrity Management**

§192.909 How can an operator change its integrity management program?

(a) *General.* An operator must document any change to its program and the reasons for the change before implementing the change.

(b) *Notification.* An operator must notify OPS, in accordance with [§192.635](#) ~~§192.949~~, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. ~~An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.~~ An operator must provide the notification within 30 days after adopting this type of change into its program.

§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 2, which are grouped under the following four categories:

- (1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;
- (2) Static or resident threats, such as manufacturing, welding/fabrication or equipment defects;
- (3) Time independent threats such as third party damage/mechanical damage, incorrect operational procedure, weather related and outside force damage; including consideration of seismicity, geology, and soil stability of the area; and
- (4) Human error such as operational mishaps and design and construction mistakes.

(b) **[Same as current]**

(c) **[Same as current]**

(d) **[Same as current]**

(e) **[Same as current]**

The only proposed changes to § 192.917 that pertain to the transmission mandates rule are those that apply to (a), including the references to consideration of seismicity, geology and soil stability in the area. PHMSA should not incorporate any other changes to this section into the second transmission final rule.

§192.921 How is the baseline assessment to be conducted?

- (a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See §192.917). In addition, an operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

- (1) Internal inspection tool or tools capable of detecting ~~corrosion, deformation and~~

~~mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, or any other~~ threats to which the

covered segment is susceptible, as determined by the operator. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. A person qualified by knowledge, training, and experience An operator must analyze the data obtained

from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;

- (2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939. ~~The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, including stress corrosion cracking, manufacturing and related defect threats, including defective pipe and pipe seams, selective seam weld corrosion, dents and other forms of mechanical damage;~~

Per the March 2, 2018 GPAC Voting Slide 5, PHMSA will “revise the language in proposed §192.921(a)(1) to clarify that operators select assessment methods based upon the threats to which the pipeline is susceptible and remove language in 192.921(a) that is duplicative of existing 192.915.”

The Associations believe the addition of §192.493 falls outside of the scope of the Congressional Mandates and therefore should not be included in the congressional mandates rule.

- (3) “Spike” ~~hydrostatic~~ pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for ~~time-dependent cracking 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;~~

Although modifications to the spike testing language were included only in the GPAC votes for §192.506, the Associations believe PHMSA should modify the language in §192.710, §192.921, and §192.937 as well. Per the March 2, 2018 GPAC Vote Slide 3, PHMSA will “revise the spike pressure test requirements proposed in §192.506 revise language to refer to time-dependent cracking.”

- (4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI);

- (5) Guided Wave Ultrasonic Testing (GWUT) conducted as described in Appendix F;

- (6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. ~~Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (d)(5) of this section.~~ An operator must conduct the direct assessment in

Per the March 2, 2018 GPAC Voting Slide 2, PHMSA will “clarify §192.921(a)(6) by stating that direct assessment may be used only if appropriate for the threat being assessment but cannot be used to assess threats for which direct assessment is not suitable.”

The Associations believe that the current language within §192.921(a)(6), “to address threats of external corrosion, internal corrosion and stress corrosion cracking,” effectively and efficiently meets the GPAC’s guidance without adding any additional unnecessary regulatory text that may create confusion or uncertainty.

accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

- (7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator choosing this option must notify the Office of Pipeline Safety (OPS) ~~180 90~~ days before conducting the assessment, in accordance with ~~§192.633 §192.949 and receive a “no objection letter” from the Associate Administrator of Pipeline Safety. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.~~

- (b) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

- (c) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §192.917(e) to address particular threats that it has identified.
- (d) *Time period.* An operator must prioritize all the covered segments for assessment in accordance with §192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.
- (e) *Prior assessment.* An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in §192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of §192.937 and §192.939.
- (f) *Newly identified areas.* When an operator identifies a new high consequence area (*see* §192.905), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.
- (g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.
- (h) *Plastic transmission pipeline.* If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of §192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.



**§192.933 What actions must be taken to address integrity issues?**

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

(1) *Temporary pressure reduction.* If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, *see* §192.7); Pipeline Research Council, International, PR-3-805 (R-STRENG) (incorporated by reference, *see* §192.7); or by reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. An operator must notify PHMSA in accordance with [§192.635](#) [§192.949](#) if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action. ~~An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement or an intrastate covered segment is regulated by that State.~~

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, the operator must notify PHMSA under [§192.635](#) [§192.949](#) and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. ~~The operator also must notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State~~

The only changes to § 192.933 in the transmission mandates rulemaking should be if PHMSA chooses to accept the Associations' recommendation to add a new general Notification process section, § 192.635.

**(b) [Same as Current]**

**(c) [Same as Current]**

**(d) [Same as Current]**

§192.935 What additional preventive and mitigative measures must an operator take?

(a) **[Same as Current]**

(b) Third party damage and outside force damage—

(1) *Third party damage.* An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—

The only proposed changes to § 192.935 that pertain to the transmission mandates rule are those that apply to (b), including the reference to seismicity. PHMSA should incorporate any other changes to this section into the second transmission final rule.

(i) Using qualified personnel

(see §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

(iii) Participating in one-call systems in locations where covered segments are present.

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502 (incorporated by reference, see §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

(2) *Outside force damage.* If an operator determines that outside force (*e.g.*, earth movement, loading, longitudinal, or lateral forces, seismicity of the area, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, relocating the line, or geospatial, GIS, and deformation in-line inspections.

(c) [Same as Current]

(d) **[Same as Current]**

(e) [Same as Current]

**§192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?**

- (a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.
- (b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917, which incorporates an analysis of updated pipe design, construction, operation, maintenance, and integrity information. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933). The evaluation must identify the threats specific to each covered segment, including interacting threats and the risk represented by these threats, and identify additional preventive and mitigative actions (§192.935).
- (c) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by any one or more of the following methods for each threat to which the covered segment is susceptible (see §192.917).-An operator must select the method or methods best suited to address the threats identified to the covered segment (See § 192.917). An operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

Although not explicitly voted by the GPAC, the Associations believe PHMSA should make the same changes in §192.937 as those voted on for §192.921.

Per the March 2, 2018 GPAC Vote Slide 2, PHMSA will “revise the language in proposed 192.921(a)(1) to clarify that operators select assessment methods based upon the threats to which the pipeline is susceptible and remove language in 192.921(a) that is duplicative of existing 192.915.”

- (1) Internal inspection tool or tools capable of detecting ~~corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, or any other~~ threats to which the covered segment is susceptible, as determined by the operator. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. A person qualified by

The Associations believe the addition of §192.493 falls outside of the scope of the Congressional Mandates and therefore should not be included in the congressional mandates rule.

~~knowledge, training, and experience~~ An operator must analyze the data obtained from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;

- (2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939. ~~The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, including stress corrosion cracking, manufacturing and related defect threats, including defective pipe and pipe seams, selective seam weld corrosion, dents and other forms of mechanical damage;~~
- (3) “Spike” ~~hydrostatic~~ pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for ~~time-dependent cracking 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;~~
- (4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data ~~needed to assess all threats~~, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI);
- (5) Guided Wave Ultrasonic Testing (GWUT) conducted as described in Appendix F;
- (6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. ~~Use of~~

PHMSA should consider spike hydrostatic test alternatives - Allow pneumatic spike tests per §192.503(b)-(c).

Although modifications to the spike testing language were included only in the GPAC votes for §192.506, the Associations believe PHMSA should modify the language in §192.710, §192.921, and §192.937 as well. Per the March 2, 2018 GPAC Vote Slide 3, PHMSA will “revise the spike pressure test requirements proposed in §192.506 revise language to refer to time-dependent cracking.”

~~direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (d)(5) of this section.~~

An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

- (7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is

susceptible. An operator choosing this option must notify the Office of Pipeline Safety (OPS) ~~180~~ 90 days before conducting the assessment, in accordance with §192.633 ~~§192.949 and receive a “no objection letter” from the Associate Administrator of Pipeline Safety. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.~~

- (8) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with §192.931.

Although direct assessment applicability changes were only included only in the GPAC votes for §192.921, the Associations believe the same changes should be made in §192.937.

Per the March 2, 2018 GPAC Vote Slide 2, PHMSA will “clarify §192.921(a)(6) by stating that direct assessment may be used only if appropriate for the threat being assessment but cannot be used to assess threats for which direct assessment is not suitable.”

The Associations believe that the current language within §192.937(a)(6), “to address threats of external corrosion, internal corrosion and stress corrosion cracking,” effectively and efficiently meets the GPAC’s guidance without adding unnecessary regulatory text that create confusion or uncertainty.

#### §192.939 What are the required reassessment intervals?

An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments.

- (a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven calendar years. Operators may request a six month extension of the seven-calendar year reassessment interval if the operator submits written notice to OPS, in accordance with [§192.633](#) ~~§192.949~~, with sufficient justification of the need for the extension. If an operator establishes a reassessment interval that is greater than seven [calendar](#) years, the operator must, within the seven-calendar year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.
- (1) *Pressure test or internal inspection or other [equivalent](#) technology.* An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by—
- (i) Basing the interval on the identified threats for the covered segment (see §192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by §192.917; or
  - (ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME B31.8S (incorporated by reference, see §192.7), section 5, Table 3.
- (2) *External Corrosion Direct Assessment.* An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE SP0502 (incorporated by reference, see §192.7).
- (3) *Internal Corrosion or SCC Direct Assessment.* An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.
- (i) Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions;
  - (ii) Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and
  - (iii) Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size.
- (b) *Pipelines Operating Below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven [calendar](#) years. An operator must establish reassessment by at least one of the following—
- (1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven [calendar](#) years, the operator must conduct by the seventh [calendar](#) year of the interval either a confirmatory direct assessment in accordance with §192.931, or a low stress reassessment in accordance with §192.941.
- (2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section.

- (3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section.
- (4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with §192.931, with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.
- (5) Reassessment by the low stress assessment method at 7-year intervals in accordance with §192.941 with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.
- (6) The following table sets forth the maximum reassessment intervals. Also refer to Appendix E.II for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

**MAXIMUM REASSESSMENT INTERVAL**

<b>Assessment method</b>	<b>Pipeline operating at or above 50% SMYS</b>	<b>Pipeline operating at or above 30% SMYS, up to 50% SMYS</b>	<b>Pipeline operating below 30% SMYS</b>
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years <sup>(*)</sup>	15 years <sup>(*)</sup>	20 years. <sup>(**)</sup>
Confirmatory Direct Assessment	7 years	7 years	7 years.
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in §192.941.

<sup>(\*)</sup>A Confirmatory direct assessment as described in §192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.

<sup>(\*\*)</sup>A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

~~§192.949—How does an operator notify PHMSA?~~

~~An operator must provide any notification required by this subpart by—~~

~~(a) Sending the notification by electronic mail to [InformationResourcesManager@dot.gov](mailto:InformationResourcesManager@dot.gov); or~~

~~(b) Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, 1200 New Jersey Ave. SE., Washington, DC 20590.~~

~~Appendix A to Part 192—Records Retention Schedule for  
Transmission Pipelines~~

Per March 2, 2018 Final GPAC  
Voting Slide 6, “Withdraw  
proposed Appendix A.”



## Appendix F to Part 192—Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

This appendix defines criteria which must be properly implemented for use of Guided Wave Ultrasonic Testing (GWUT) as an integrity assessment method. Any application of GWUT that does not conform to these criteria is considered “other technology” as described by §§ 192.710(c)(7), 192.921(a)(7), and 192.937(c)(7), for which OPS must be notified ~~90~~ ~~180~~ days prior to use in accordance with §§ 192.921(a)(7) or 192.937(c)(7). GWUT in the “Go-No Go” mode means that all indications (wall loss anomalies) above the testing threshold (a maximum of ~~20~~ ~~5~~% of cross sectional area (CSA) sensitivity) be directly examined, in-line tool inspected, pressure tested or replaced prior to completing the integrity assessment on the cased carrier pipe or other GWUT application.

- I. *Equipment and Software: Generation.* The equipment and the computer software used are critical to the success of the inspection. Guided Ultrasonic LTD (GUL) Wavemaker G3 or G4 with software version 3 or higher, or equipment and software with equivalent capabilities and sensitivities, must be used.
- II. *Inspection Range.* The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at ~~20~~ ~~5~~% cross sectional area (CSA). A signal that has an amplitude that is at least twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (T’s, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and

Per voting slide for Strengthening IM Assessment methods, bullet 2 –  
“Revise the ‘no objection’ process as recommended by members at GPAC per the recommended procedure under §192.607...”

There are potential application for GWUT other than cased crossings, including assessments of short vertical risers.

A typical industry lower cutoff for further review of GWUT results is 20-25% of CSA sensitivity. Restricting GWUT to 5% of CSA or less will severely limit the use of this technology. Although operators have previously agreed to 5% CSA as part of “other technology” notifications for segments covered by Subpart O, PHMSA now proposes to require integrity assessments for a much larger population of pipelines. PHMSA should consider a less restrictive approach.

Typically, operators consider both amplitude of reflection (CSA sensitivity) and circumferential extent when determining which GWUT results warrant further assessment. PHMSA could consider requiring operators to further assess GWUT results as follows:

- For CSA sensitivity below 5%, no further assessment required
- For CSA sensitivity between 5% and 10%, further assessment required if circumferential extent is less than 25%
- For CSA sensitivity between 10% and 20%, further assessment required if circumferential extent is less than 50%
- For CSA sensitivity more than 20%, further assessment always required.

influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. ~~In general the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.~~

- III. *Complete Pipe Inspection.* To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio across the entire pipeline segment that is inspected. This may require multiple GWUT shots. Double ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.
- IV. *Sensitivity.* The detection sensitivity threshold determines the ability to identify a cross sectional change. The maximum threshold sensitivity cannot be greater than 20 5% of the cross sectional area (CSA).  
The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented. All wall loss defect indications in the "Go-No Go" mode above the 20 5% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced prior to completing the integrity assessment.
- V. *Wave Frequency.* Because a single wave frequency may not detect certain defects, a minimum of three frequencies must be run for each inspection to determine the best frequency for characterizing indications. The frequencies used for the inspections must be documented and must be in the range specified by the manufacturer of the equipment.
- VI. *Signal or Wave Type: Torsional and Longitudinal.* Both torsional and longitudinal waves must be used in the course of the assessment and use must be documented. In most cases torsional wave will be used for the majority of the assessment and be complemented by longitudinal wave in the areas of the collar.
- VII. *Distance Amplitude Correction (DAC) Curve and Weld Calibration.* The Distance Amplitude Correction curve accounts for coating, pipe diameter, pipe wall and environmental conditions at the assessment location. The DAC curve must be set for each inspection as part of establishing the effective range of a GWUT inspection. DAC curves provide a means for evaluating the cross sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.
- VIII. *Dead Zone.* The Dead Zone is the area adjacent to the collar in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. Because the entire line must be inspected, inspection procedures must account for the dead zone by requiring the

In proposed Appendix F, use of both torsional and longitudinal signal is required, but the extent that each type must be used is not clear. GWUT would become impractical in most cases if both signals are required on the entire segment because the longitudinal signal cannot be used on buried segments. The longitudinal signal is used only to spot check the exposed areas where the collar is installed. Per Member Drake (12/15/2017 Transcript pg. 146): "requirements of both torsional and longitudinal wave modes in all situations introduce unnecessary complexity into the guided wave ultrasonic data interpretation process. Specifically, torsional wave mode is the primary wave made when utilizing GWUT. Longitudinal wave mode may be used as an optional secondary mode."

movement of the collar for additional inspections. An alternate method of obtaining valid readings in the dead zone is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

- IX. *Near Field Effects.* The Near Field is the region beyond the Dead Zone where the receiving amplifiers are increasing in power, before the wave is properly established. Because the entire line must be inspected, inspection procedures must account for the near field by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the near field is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.
- X. *Coating Type.* Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance. Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the assessed cased pipe, then another type of assessment method must be utilized.
- XI. *End Seal.* When assessing cased carrier pipe with GWUT, operators must remove the end seal from the casing at each GWUT test location to facilitate visual inspection. Operators must remove debris and water from the casing at the end seals. Any corrosion material observed must be removed, collected and reviewed by the operator's corrosion technician. The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range.
- XII. *Weld Calibration to set DAC Curve.* Accessible welds, along or outside the pipe segment to be inspected, must be used to set the DAC curve. A weld or welds in the access hole (secondary area) may be used if welds along the pipe segment are not accessible. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. There must not be a weld between the transducer collar and the calibration weld. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve may be required. Alternative means of calibration can be used if justified by sound engineering analysis and evaluation.
- XIII. *Validation of Operator Training.* There is no industry standard for qualifying GWUT service providers. Pipeline operators must require all guided wave service providers to have equipment-specific training and experience for all GWUT Equipment Operators which includes training for:
- A. equipment operation,
  - B. field data collection, and
  - C. data interpretation on cased and buried pipe.

The Associations believe the statement that "there is no industry standard for qualifying GWUT service providers" is inappropriate for regulatory text.

Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, may operate the equipment.

A Senior Level GWUT Equipment Operator with pipeline specific experience must provide onsite oversight of the inspection and approve the final reports. A Senior Level GWUT Equipment Operator must have additional training and experience, including but not limited to training specific to cased and buried pipe, with a quality control program which conforms to Section 12 of ASME B31.8S.

Training and Experience Minimums for Senior Level GWUT Equipment Operators:

- Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe
- Training, qualification and experience in testing procedures and frequency determination
- Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)
- Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

- XIV. *Equipment: traceable from vendor to inspection company.* The operator must maintain documentation of the version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., in the report.
- XV. *Calibration Onsite.* The GWUT equipment must be calibrated for performance in accordance with the manufacturer's requirements and specifications, including the frequency of calibrations. A diagnostic check and system check must be performed on-site each time the equipment is relocated [to a different casing or pipe segment](#). If on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until the equipment can be restored to manufacturer's specifications.
- XVI. *XVI. Use on Shorted Casings (direct or electrolytic).*  
~~GWUT may not be used to assess shorted casings. GWUT operators must have operations and maintenance procedures (see § 192.605) to address the effect of shorted casings on the GWUT signal.~~  
The equipment operator [must assure the accuracy of the data is not compromised by the shorted casing, and only use data which meets the specification.](#) ~~clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures.~~ All shorted casings found while conducting GWUT inspections must be addressed by the operator's standard operating procedures [under 192.605](#).
- XVII. *Direct examination of all indications above the detection sensitivity threshold.*  
The use of GWUT in the "Go-No Go" mode requires that all indications (wall loss anomalies) above the testing threshold ([20 5%](#) of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe [or other GWUT application](#). If this cannot be accomplished then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.
- XVIII. *Timing of direct examination of all indications above the detection sensitivity threshold.*  
Operators must either replace or conduct direct examinations of all indications ([wall loss anomalies](#)) identified above the detection sensitivity threshold according to the table below. Operators must conduct leak surveys and reduce operating pressure as specified until the pipe is replaced or direct examinations are completed.

The Associations believe the technology supporting GWUT has improved dramatically and cased pipes that have a metallic short or electrolytic short can still potentially be assessed.

Required Response to GWUT <u>Wall Loss</u> Indications			
GWUT Criterion	Operating Pressure less than or equal to 30% SMYS	Operating pressure over 30 and less than or equal to 50% SMYS	Operating pressure over 50% SMYS
Over the detection sensitivity threshold (maximum of <u>20</u> <del>5</del> % CSA)	Replace, <del>or</del> direct examination, <u>or alternative assessment</u> , within 12 months, and instrumented leak survey once every 30 calendar days.	Replace, <del>or</del> direct examination, <u>or alternative assessment</u> , within 6 months, and instrumented leak survey once every 30 calendar days, and maintain MAOP below the <u>highest actual operating pressure sustained by the pipeline within two years prior to at time of</u> discovery.	Replace, <del>or</del> direct examination, <u>or alternative assessment</u> , within 6 months, and instrumented leak survey once every 30 calendar days, and reduce MAOP to 80% of <u>the highest actual operating pressure sustained by the pipeline within two years prior to at time of</u> discovery.

PHMSA proposes to allow alternative assessment methods when GWUT indications exceed the detection sensitivity threshold. This must be reflected in the table above.

Also, operators should be permitted to consider recent operating pressures when establishing an appropriate pressure reduction. It is overly restrictive to require operators to base pressure reductions off the moment of discovery. This will discourage the use of this technology.

#### IV. Code Sections Recommended for Inclusion in Second Transmission Rule

PHMSA's proposed changes to or addition of the following code sections do not pertain to congressional mandates and should be addressed in the second gas transmission rulemaking:

Definitions
§192.3: Close Interval Survey, Electrical Survey, Significant seam cracking, significant stress corrosion cracking
Standards Incorporated by Reference
§192.7 (b),(g),(k)
Management of Change
§192.13(d)
Strengthened Assessment Methods
§192.150, §192.493, §192.923, §192.927, §192.929,
Corrosion Control
§192.319, §192.465, §192.473, §192.478, §192.935(f),(g), Appendix D
Anomaly Response and Repair Criteria
§192.485, §192.711, §192.713, §192.933,
Surveillance After Extreme Weather Events
§192.613
Safety of Launchers and Receivers
§192.750
Integrity Management Clarifications
§192.911, §192.917(b)-(e), §192.935(a),(d), §192.941, Appendix E,

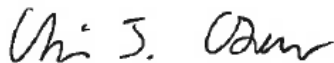
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