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

Pipeline Safety: Repair Criteria	)	
for Hazardous Liquid and Gas	)	Docket No. PHMSA-2025-0019
Transmission Pipelines	)	

COMMENTS IN RESPONSE TO "REPAIR CRITERIA FOR HAZARDOUS LIQUID AND GAS TRANSMISSION PIPELINES" ADVANCE NOTICE OF PROPOSED RULEMAKING

FILED BY
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I. INTRODUCTION

Pursuant to 49 C.F.R. § 190.317, the Interstate Natural Gas Association of America (INGAA), American Gas Association (AGA), and GPA Midstream Association (GPA Midstream) (collectively, the Associations) submit comments on the Advance Notice of Proposed Rulemaking (ANPRM) issued by the Pipeline and Hazardous Materials Safety Administration on May 21, 2025. The ANPRM requests stakeholders input on, among other things, potential opportunities to improve the cost-effectiveness of the current part 192[1] repair requirements applicable to gas transmission pipelines.[2]

INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 29 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.

Founded in 1918, AGA represents more than 200 local energy companies committed to the safe and reliable delivery of clean natural gas to more than 180 million Americans. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industrial associates. Today, natural gas meets more than one-third of the United States' energy needs.

Shaping the United States' midstream energy sector since 1921, GPA Midstream has nearly 50 corporate members, who are responsible for the safe and efficient gathering, processing, transporting, and marketing of natural gas, natural gas liquids, crude oil, and refined products. Collectively, GPA Midstream members operate more than 506,000 miles of pipelines and over 365 natural gas processing facilities. They are the invisible link between raw natural gas and crude oil produced at the wellhead and the distribution of products to consumers for heating, electricity production, transportation, steelmaking, fertilizer production, plastics, high-tech devices, cosmetics, pharmaceuticals, and much more.

Pipeline safety is a top priority for the Associations and their members. The Associations support strong pipeline safety requirements and have endorsed PHMSA's recent regulatory initiatives that strengthened and enhanced pipeline safety requirements. Such measures are important to advancing the industry's efforts to facilitate the integrity and reliability of the nation's natural gas pipeline infrastructure.

Yet, as explained in the ANPRM, the current part 192 pipeline safety standards applicable to remediating and repairing pipeline anomalies apply both prescriptive requirements applicable to all pipelines and risk-based integrity management (IM) requirements that apply to pipeline segments located in high consequence areas (HCA). While the safety record of pipelines has

[1] 49 C.F.R. Part 192 (2023).
[2] Pipeline Safety: Repair Criteria for Hazardous Liquid and Gas Transmission Pipelines, Advance Notice of Proposed Rulemaking, 90 Fed. Reg. 21,715 (May 21, 2025).

improved in recent years, PHMSA's ANPRM observes that some repair requirements have not been updated for a number of years and other requirements may not account for the latest advances in pipeline safety technologies and industry best practices. PHMSA suggests that updating repair criteria may be needed to align with recent changes to Part 192 regulations, to minimize barriers to the development and deployment of innovation, safety technologies and industry best practices, and to avoid overlapping regulatory requirements.

The Associations share PHMSA's observations and concerns and welcome the ANPRM's request for input on how to improve and modernize the current regulations. Regulatory revisions are needed to remove impediments to the industry's ability to deploy advances in technologies, improved processes, and greater research in specific material characteristics. The Associations support the removal of internal inconsistencies and tensions within the existing regulations, and allow implementation of cost-effective and efficient technologies, processes, and recent research to manage pipeline anomalies. The Associations are confident that these objectives can be achieved in a reasonable, practicable, and responsible manner that does not compromise pipeline safety or safety to the public.

The Associations offer their responses to the ANPRM's specific questions seeking stakeholder feedback on various issues related to existing anomaly repair criteria, remediation timelines, and integrity management regulations applicable to gas transmission pipelines under Part 192. The Associations also address issues affecting gas gathering pipelines.
The Associations support the comments submitted by the American Petroleum Institute and Liquid Energy Pipeline Association.

II. COMMENTS

Section III.A of the ANPRM poses a number of questions related to anomaly repair criteria, remediation timelines and integrity management requirements applicable to both gas transmission pipelines and hazardous liquid pipelines. Section III.C poses questions specific to gas transmission pipelines. The comments of the Associations focus on issues relevant to gas transmission pipelines under Part 192, and where applicable, address issues relevant to gas gathering pipelines.
Appendix A contains the Associations recommended amendments to the regulatory text of Part 191 and Part 192. The Associations will provide more detailed cost information at a later date.

Incident data reported to PHMSA under § 192.15 were analyzed and evaluated as part of the preparation of the Association's comments on this ANPRM. The work included incident data reported to PHMSA by onshore gas transmission operators from 2010 through the first quarter of 2025. The 2010 timeframe has been selected for conducting such analyses, as this represented the completion of the first decade of integrity management. PHMSA also modified the incident reporting form to include more data fields that provide greater insights into pipeline safety performance.

In analyzing incidents that involved dents during 2010 through the 1Q of 2025, there were:

- No incidents that were solely a result of plain dents,
- No incidents attributable to dents with metal loss,
- No incidents attributable to dents intersecting a weld/ seam (girth and long)

This experience demonstrates that, in general, dents and even dents with metal loss represent very low risk. First, it shows that the repair criteria being used for plain dents in B31.8 are sufficiently conservative and have been effective. Second, the criterion established for dents with metal loss may have been overly conservative. In developing the original version of ASME B31.8S, the Integrity Management Supplement to B31.8, the development task group established a very conservative criterion for dents with metal loss. They did so, wanting to gain experience in evaluating and managing dents with metal loss. In the interim, B31.8 developed criteria for dents related to metal loss at section 851.4.1(f), which stipulates that for dents less than 6% in depth, where the failure pressure ratio for the corresponding metal loss is less than the MAOP, the dent can be monitored. This represents a threshold value at which dents with metal loss can be monitored as a condition. Although not currently specified in the regulations, the Associations recommend that PHMSA adopt this criterion for inclusion in repair criteria through incorporation in § 192.7.

Incidents that involved dents with cracking were also analyzed and evaluated in the period of 2010 through the 1Q of 2025. Of 1,655 incidents reported to PHMSA, there were six incidents resulting from dents with cracking. i.e., 0.36% of the incidents. For the approximate 298,000 miles of onshore gas transmission, that yields an incident rate of 1.44 x 10-6/mile/ year. Simply stated that is slightly more than 1 in 1 million in a year's time frame across the US natural gas transmission infrastructure. None of the incidents resulted in fatalities or injuries.

Regarding the six incidents with dents and cracking, all were dents on the bottom side of the pipe. All resulted in leaks, except for one that led to a rupture. The one rupture was on a lateral serving a power plant. One of the incidents was voluntarily reported by the operator, as per the provision in § 191.15. A dent was identified in the ILI log. Company personnel used leak detection equipment to identify the location, they excavated area, and found the leak.

From a big picture perspective, dents with cracking represent a very small risk. As discussed below, in working with PHMSA staff in application of engineering critical analyses (ECAs), it became apparent that PHMSA staff felt the need to apply extra conservatism with ECAs for dents under § 192.712(c), and even other applications using ECAs outside the scope of this rulemaking, including § 192.624. For example, in applying § 192.712(c), PHMSA has been expecting operators to conduct finite element analyses (FEAs) for all dents even though, the language in § 192.712(c)(6) states "Finite Element Analysis, or other technology." This analysis demonstrates that there is no basis for PHMSA wanting to apply additional conservatism to the dent ECA process in the rule today in § 192.712(c), and for example, there is no reason to require FEA on all dents and PHMSA should allow for use of "other technology."

A. ANPRM Section III.A - General

ANPRM Question III.A.1.

"Do the anomaly repair criteria, remediation timelines, and IM regulations for gas transmission pipelines (Part 192, Subparts M and O) and hazardous liquid and carbon dioxide pipelines (§§ 195.401 and 195.452(h)(4)) strike an appropriate balance between safety benefits and compliance costs? If not, should PHMSA consider amending any of those provisions? Please identify any specific regulatory amendments that merit reconsideration, as well as the technical, safety, and economic reasons supporting those recommended amendments."

Comments of the Associations on Question III.A.1.

PHMSA's pipeline anomaly repair criteria and remediation timelines for gas transmission pipeline segments located outside of HCAs and within HCAs are set forth in § 192.714 (non-HCA pipeline segments) and § 192.933 (HCA pipeline segments), respectively. Implementing the requirements of these sections requires reference to the requirements of § 192.712 which prescribes how an operator determines a pipeline segment's predicted failure pressure and remaining life at the location of an anomaly.

Some of these regulations impose overly prescriptive requirements that may not appropriately balance safety benefits and compliance costs. In some situations, the use of advanced technologies and generally accepted engineering analyses can achieve the same, or better, safety outcomes more efficiently.

The Associations recommend that PHMSA consider the following issues.

1. PHMSA should amend confusing repair criteria terminology.

First, PHMSA should clarify the difference between "anomaly" v. "defect" and "response" v. remediation" v. "repair." Sections 192.712, 192.714, and 192.933 use certain terms interchangeably even though they have different meanings. Specifically, the terms "anomaly" and "defect" mean different things, but the regulations treat them, in places, as synonyms and in other places as different terms. An anomaly is a feature or imperfection on a pipeline that is detected during an assessment.[3] An anomaly may or may not be a "defect." An operator performs further

[3] PHMSA's online glossary states that a "pipeline anomaly is generally thought of as an imperfection in the wall of the pipe. Many pipeline anomalies result during the pipe manufacturing process and don't affect the performance of the pipeline or its ability to function in a safety manner. Other pipeline anomalies are caused by corrosion or damage to the pipe from outside forces like digging equipment. Some of these can be detrimental to the integrity of the pipeline if not repaired." Pipeline & Hazardous Materials Safety Administration. "Pipeline Glossary." *Pipeline Safety Stakeholder Communications*, U.S. Department of Transportation, 2019, primis.phmsa.dot.gov/comm/glossary/index.htm?nocache=8115#Anomaly. Accessed 19 July 2025.

examination and assessment on an anomaly to determine whether it is a "defect" that presents a risk to pipeline integrity. Defects require a repair or remediation.

The terms "response," "remediation," and "repair" also have different meanings but are sometimes confused in the regulations. A "response" constitutes the further examination and assessment an operator performs on an anomaly to determine if it presents a risk to pipeline integrity. A "response" precedes a "remediation" or "repair" which are activities performed to correct a defect in a pipe.

The Associations recommend that PHMSA amend §§ 192.712, 192.714, and 192.933 to more precisely reflect the different meanings of these terms. Such revisions would make the regulations and operators' compliance obligations clearer. In addition, these proposed revisions should align with the language in Section 7 of ASME B31.8S (2018), which is incorporated by reference into §§ 192.714(c) and (d) and 192.933(c) and (d).

2. *Required responses to crack-like anomalies in §§ 192.714 and 192.933 are overly prescriptive.*

PHMSA should adopt a performance-based approach to crack-like anomaly assessment that allows operators to distinguish between benign manufacturing defects and genuine integrity threats, reducing unnecessary costs while maintaining safety.

Sections 192.714(d)(1)(v)(A) and 192.933(d)(1)(v)(A) require that an operator treat as an immediate repair condition "a crack or crack-like anomaly meeting any of the following criteria: (A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness; or (B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth."[4] The requirement to treat these anomalies as immediate repair conditions without first allowing for examination and assessment, requires that operators incur costs and cause adverse environmental, landowner, and pipeline operational impacts that outweigh the resulting safety benefit.

Operators are increasingly using more advanced inline inspection (ILI) tools, including Electro Magnetic Acoustic Transducer (EMAT), and ultra-high resolution axial and circumferential ILI tools, that detect a greater number of smaller, more benign features in the body and the seam of the pipeline such as minor wall thickness variations, previously undetected geometric formations that fall within pipe manufacturing tolerances, and seam related anomalies. Often, these features are time-independent manufacturing-related anomalies (e.g., hook cracks, lack of fusion, and laminations) that have existed in the pipeline since construction, and they do not pose a threat to pipeline integrity. Many of these features have survived mill testing and post-construction pressure testing. According to § 192.917(e)(3), an operator can consider this type of threat as a stable manufacturing defect if the pipeline has been subjected to a subpart J pressure test to at least 1.25 times maximum allowable operating pressure (MAOP), has not experienced an incident since that pressure test, the MAOP has not increased, the stresses leading to cyclic fatigue have not increased, and no interacting threats destabilized a stable manufacturing defect, per § 192.917(c)(2).

[4] 49 C.F.R. §§ 192.714(d)(1)(v)(A), 192.933(d)(1)(v)(A).

Note that PHMSA will need to update § 192.917(e)(3) to account for the technical correction in the final rule, "Pipeline Safety: Clarifying Recordkeeping Requirements for Testing in MAOP Reconfirmation Regulation"[5]). This correction clarified the allowance of pre-1970 pressure tests to be considered in the application of § 192.917(e)(3). Since § 192.917(e)(3) directly references subpart J, pressure tests and pre-code pressure tests would not be able to meet the record requirements of subpart J without an amendment.

Sections 192.714(d)(1)(v)(A) and 192.933(d)(1)(v)(A) do not allow an operator to perform an engineering analysis to discern between benign stable manufacturing-related crack-like anomalies and time-dependent crack-like anomalies that may be associated with more serious cracking conditions. As a result, operators often must perform unnecessary excavations that can cause service disruptions and have adverse impacts associated with land disturbance and methane emissions.

The compliance costs associated with having to repair benign anomalies are further exacerbated by § 192.917(e), which requires that, if an operator discovers cracking or corrosion on a covered segment, the operator must evaluate and remediate all other similar pipeline segments. The operator's inability to evaluate and assess crack-like anomalies and the incurring of these unnecessary costs frustrate an operator's ability to take full advantage of the benefits associated with technological advancements in assessment methods. Beyond these direct costs, the current framework forces operators to allocate resources toward investigating anomalies that pose no integrity threat.

A performance-based framework enables operators to apply engineering judgment, advanced assessment techniques and processes, and utilize the most recent research to prioritize threats based on actual risks. Therefore, the Associations request that §§ 192.714(d)(1)(v)(A) and 192.933(d)(1)(v)(A) be amended to reflect a performance-based framework that provides operators with the ability to examine and assess crack-like anomalies with metal loss greater than 50 percent of pipeline's wall thickness and determine whether the anomaly poses a threat to pipeline integrity.

3. *The current 50 percent metal loss threshold for crack repair does not reflect the most current technical research.*

The current 50 percent metal loss threshold for crack repair does not reflect the most current technical understanding and could benefit from alignment with established industry standards and recent research findings. The imbalance between compliance costs and safety benefits also is reflected in the metal loss thresholds requiring a response under the §§ 192.714 and 192.933 repair criteria and in § 192.712 when calculating a pipeline's predicted failure pressure and remaining life. These existing thresholds exceed safety margins that are needed to protect the integrity of a

[5] Pipeline and Hazardous Materials Safety Administration, "Pipeline Safety: Clarifying Recordkeeping Requirements for Testing in MAOP Reconfirmation Regulation," 90 Fed. Reg. 28,054 (July 1, 2025), https://www.govinfo.gov/content/pkg/FR-2025-07-01/pdf/2025-12115.pdf.

pipeline. PHMSA adopted the 50 percent threshold in 2022, stating that it was "consistent with research findings."[6]

A review of the studies cited by PHMSA in support of the 50 percent threshold reveals that these sources do not directly establish depth-based repair criteria. The 2017 Battelle Report—a PHMSA-funded work—focuses specifically on electric resistance welded (ERW) and flash welded (FW) pipe to improve technologies used to detect and characterize cracking. However, it does not address the full breadth of pipe types in service today. Similarly, the Joint Industry Project cited by PHMSA also does not establish depth-based repair criteria. In fact, the report states that:

> ".... those [cracks] that are so short that, even if they were 50% through-wall depth, they would not result in a hydrostatic test failure." p. 104.

API RP 1176, Recommended Practice for Assessment and Management of Cracking in Pipelines, First Edition, Includes Errata 1 (2021) and Errata 2 (2022) provides the basis for an immediate depth-based criterion for cracking. The standard establishes "a depth greater than 70% of the nominal wall" as an immediate condition. The Associations recommend that PHMSA incorporate this standard by reference for use in § 192.714(d)(1)(v)(A) and § 192.933(d)(1)(v)(A), so that operators are not required to treat cracking with metal loss as an immediate repair condition unless depth reaches the 70 percent threshold, consistent with updated recommended practice.

The BMT Fleet Technologies document, "Fatigue Considerations for Natural Gas Transmission Pipelines"[7] evaluated multiple pipeline parameters: various wall thicknesses, grades, and diameters to develop a conservative crack evaluation process, called the Fatigue Susceptibility Rapid Assessment. The Fatigue Susceptibility Rapid Assessment process found that cracks at depths of 50% to 70% through wall could remain in the pipeline for 100 years before growing to failure. The Associations request that PHMSA allow the use of a process like the Fatigue Susceptibility Rapid Assessment in § 192.712(d) to determine whether characteristics of the crack require repair or whether the crack can remain in service. Following the Fatigue Susceptibility Rapid Assessment provides a quick conservative evaluation to determine whether a crack requires further analysis to determine if a repair is needed or whether it can be left in service.

An example of a method of being able to assess and compare the cyclic severity of a pressure time history is through the use of a Spectrum Severity Indicator (SSI). One example of an SSI is to calculate the number of cycles of a given pressure range required to grow a crack the same amount as the actual pressure time history over one year. In the figure below, conservatively shows that a pipeline that has 1000 SSI cycles (e.g., liquid pipeline), could have a 30% deep crack that is 1 inch in length and have 100 years before the crack would grow to failure. Similarly, the same pipe that experiences 50 SSI cycles (e.g., natural gas pipeline) could have nearly a 70% deep crack and be 1 inch in length and have 100 years before the crack would grow to failure.

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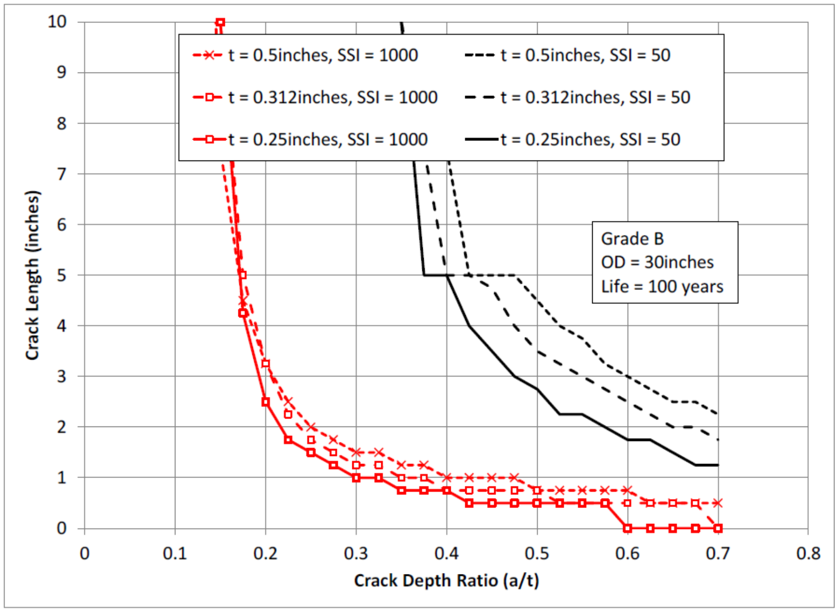
[6] Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, Final Rule, 87 Fed. Reg. 52,224, 52,248 (Aug. 24, 2022) (citing ASME, "STP-PT-0011: Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas" (2008) and Young, B.A., et al., "Comprehensive Study to Understand Longitudinal ERW Seam Failures" (2017). Accessible at: https://primis.phmsa.dot.gov/rd/FileGet/11619/Phase2FinalReport_170816_Final.pdf (Last Accessed: July 21 2025).

[7] BMT Fleet Technology, "Fatigue Considerations for Natural Gas Transmission Pipelines," Reference: 30348.FR (Rev. 01) (June 29, 2016).



4. Immediate condition for cracking based on failure pressure

In making the recommendation to change the depth criterion to 70%, the Associations recognize the importance of remaining life and failure pressure calculations, i.e., moving to a less conservative depth criterion places more importance on failure pressure calculations. In the gas transmission rule as originally promulgated on October 1, 2019, there was an immediate condition of 1.25 x MAOP, meaning that if the failure pressure was less than or equal to 1.25 times the MAOP of the pipeline segment, it required immediate examination and based on the condition of the anomaly found in the excavation, recoating of the pipe, a repair or cut out. INGAA filed a Petition for Reconsideration, which was denied by PHMSA. INGAA sought review at the the United States Court of Appeals and the provision was remanded to PHMSA.[8] INGAA asserted throughout the rulemaking process and ensuing litigation that 1.1 x MAOP was a sufficient and a technically supported standard. The Associations remain steadfast in their support of 1.1 x MAOP for cracking and recommend that PHMSA establish that standard by incorporating API RP 1176, Assessment and Management of Cracking in Pipelines, and specifically, section 11.7.2, Immediate Response Conditions which is the same section that cites the 70% depth threshold.

[8] *Interstate Natural Gas Association of America v. PHMSA*, 114 F.4th 744 (D.C. Cir. Aug. 16, 2024).

5. *The toughness values in §§ 192.712(d)(3) and 192.712(e)(2)(i) are unsupported and should be removed.*

Section 192.712 contains several requirements addressing the assessment of cracks and crack-like anomalies. While the Associations agree that PHMSA should ensure that operators use prudent engineering analysis using appropriate assessment methods and material properties, the current requirements are not aligned with current industry scientific knowledge. As written, these requirements result in misallocation of resources and impede innovation by limiting the ability of operators to fully leverage the benefits of ILI technologies, such as EMAT.

Section 192.712(d)(1) states that "[W]hen analyzing cracks and crack-like defects an operator must determine predicted failure pressure, failure stress pressure, and crack growth using technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both)…". Section 192.712(e)(2)(i) specifies the values an operator must use for material toughness. More specifically, § 192.712(e)(2)(i)(C) and (D) specify maximum Charpy v-notch toughness values for "cold weld, lack of fusion, and selective seam weld corrosion defects."

This § 192.712 language suggests that cracks and crack-like defects (such as cold weld, lack of fusion, and selective seam weld corrosion defects) exhibit similar behavior in pressurized pipe. This is not true as these crack-like anomalies in gas pipelines, which generally are not subjected to pressure cycling fatigue, are not sharp at the tip. They therefore have a higher resistance to fractures. Treating these anomalies as sharp cracks is not technically justified and results in unnecessary repairs unless potential for fatigue damage exists. Many of these anomalies have been successfully pressure tested, and an operator is permitted to treat them as stable manufacturing or construction defects.

Section 192.712(e)

Section 192.712(e) generally addresses toughness in terms of Charpy v-notch impact energy (CVN). If traceable, verifiable, and complete records for pipe and material properties do not exist, §§ 192.712(e)(2)(i)(C) and (D) mandate the use of extremely high impact toughness for pressure test evaluation and extremely low and technically unjustified values of CVN. No consideration is given to the shear area. Nor are other, more appropriate, ASTM E1820-18[9] fracture toughness testing methods mentioned. This omission is very limiting as some of the current prescribed CVN values are not as representative of the true material toughness and are therefore very conservative for use in fracture mechanics models which utilize CVN as an input (e.g., Corlas, log-secant). Consequently, the requirements related to the treatment of toughness values in § 192.712(d) are not aligned with the state of science in fracture mechanics.

PHMSA established default values for material toughness at § 192.712(e)(2)(i)(C) and (D), where an operator lacks material toughness data, data from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer may be used, or the operator may verify material properties under § 192.607. The values in § 192.712 were proposed by INGAA using data gathered from INGAA members in 2016. Structural Integrity Associates recommended use of the tenth percentile of data provided by members and yielded the values in § 192.712. Those

[9] ASTM E1820-18, "Standard Test Method for Measurement of Fracture Toughness" (Feb. 05, 2019).

were appropriately very conservative values at that point in time. Since then, transmission operators have conducted thousands of material toughness tests and conducted additional research, in PR350-233804-R01, "Comprehensive Review of SSWC Assessment"[10], as described below. This rulemaking provides an opportunity to update the basis for establishing material toughness values.

The Associations recommend removing the prescriptive toughness values set forth in § 192.712(e)(2) and request that PHMSA allow operators to use the more appropriate CVN and toughness values reflected in the PRCI report entitled "PR276-223814-R01 Pragmatic Application of MegaRule RIN 1 - 192.712 Toughness Values"[11] or use the processes defined in "PR-276-223814 Pragmatic Application of MegaRule RIN 1 - 192.712 Toughness Values L2 and L3 Procedures"[12] or similar processes when more information is known about the material. These reports provide comprehensive guidance based on established science and a large dataset of CVN values from several pipeline operators covering various vintages, manufacturing methods and pipe types. The methodologies explicitly account for the effects of temperature, loading conditions and material specific fracture behavior and preserve the intent of the current regulations. The research provides three levels of analysis dependent upon the known material characteristics and material specific fracture behavior. Level 1 is the simplest and is a very conservative method given the lack of data. These values are shown below. These values could be used in place of the existing 192.712(e)(2)(i) and could be used to meet the requirements 192.712(e)(2)(i)(A). Operators should be able to utilize more pipe specific values from industry databases or newer research to assist in obtaining values that meet the requirements of 192.712(e)(2)(i)(A).

Charpy Upper-Shelf Energy	**All base metals & modern seam welds and HAZ's**	**Vintage DSAW exhibiting ductile behavior at operating temperatures**	**Vintage LF-ERW/EFW exhibiting ductile behavior at operating temperatures**	**Vintage DC-ERW exhibiting ductile behavior at operating temperatures**	**Current 192.712(e)(2)(i) body values**	**Current 192.712(e)(2)(i) seam values**
Value with no prior failures on the pipeline	19.0 ft.-lbs.	19.0 ft.-lbs.	17.0 ft.-lbs.	9.0 ft.-lbs.	13.0 ft.-lbs.	4.0 ft.-lbs.
Value used on a pipeline with a previous failure	14.0 ft.-lbs.	14.0 ft.-lbs.	12.0 ft.-lbs.	4.0 ft.-lbs.	5.0 ft.-lbs.	1.0 ft.-lbs.

[10] Wang, J. et al. "Comprehensive Review of SSWC Assessment." Pipeline Research Council International (PRCI) Project No. IM-3-03, Contract PR350-233804, 2025.
[11] Wilkowski, G. et al. "Pragmatic Application of MegaRule RIN 1 - 192.712 Toughness Values Level 1 Analyses", Pipeline Research Council International (PRCI) Project No. IM-1-8, Contract PR-276-223814, 2024.
[12] Wilkowski, G. et al. "Pragmatic Application of MegaRule RIN 1 - 192.712 Toughness Values L2 and L3 Procedures", Pipeline Research Council International (PRCI) Project No. IM-1-08, Contract PR-276-223814, 2024.

Only a small percentage of the data examined had cases where non-ductile (brittle) initiation was predicted for vintage DC/LF-ERW/EFW fusion line and DSAW deposited weld metals. There is a range of toughness even with brittle initiation behavior determined from a procedure called the Master Curve or Reference Toughness Curve, but since there is no data on this material, the lower-shelf toughness of the material-specific Reference Toughness Curve was used, giving results similar to the recommendation from the MAT-8 User Guide.

Report PR-276-223814 Pragmatic Application of MegaRule RIN 1 - 192.712 Toughness Values L2 and L3 Procedures provides a Level 2 evaluation that can be used when the operator has Charpy data for the materials in their line. The Charpy data may only be at one temperature and may be from subsize specimens. From this data, procedures are given to take that single temperature data, account for specimen size, and assess if the material will have ductile initiation behavior for the thickness of the pipe with a bounding axial surface-crack size. With ductile-initiation behavior, the upper-shelf toughness can be used in certain burst pressure predictive analyses. The Charpy energy at the minimum operating temperature or testing temperature would be too conservative in these cases. The operator can use a Level 3 evaluation when the operator has more detailed fracture mechanics data.

PHMSA should clarify that other toughness factors can be used in place of CVN values. The "PR276-223814-R01 Pragmatic Application of MegaRule RIN 1 - 192.712 Toughness Values" report also provides other equivalent initiation fracture toughness calculations that are used in other models. The table below shows the calculations used to conservatively determine fracture toughness for Level 1 evaluations when the pipeline material characteristics are unknown. This level has greater conservatism than the other levels where data is known. These equations can be used to generate fracture toughness values that could be used in place of the existing 192.712(e)(2)(i) CVN values and could be used to meet the requirements 192.712(e)(2)(i)(A). Operators could use more pipe specific values or newer research to assist in obtaining values that meet the requirements of 192.712(e)(2)(i)(A).

Recommended K_{Jc} for $K_{Jc}/_{Jc}$ based burst pressure models (psi-in$^{0.5}$)	**All base metals & modern seam welds and HAZ's**	**Vintage DSAW exhibiting ductile behavior at operating temperatures**	**Vintage LF-ERW/EFW exhibiting ductile behavior at operating temperatures**	**Vintage DC-ERW exhibiting ductile behavior at operating temperatures**
Value with no prior failures on the pipeline	$K_{jc} = \sqrt{\frac{570\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$	$K_{jc} = \sqrt{\frac{570\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$	$K_{jc} = \sqrt{\frac{510\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$	$K_{jc} = \sqrt{\frac{270\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$
Value used on a pipeline with a previous failure	$K_{jc} = \sqrt{\frac{420\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$	$K_{jc} = \sqrt{\frac{420\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$	$K_{jc} = \sqrt{\frac{360\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$	$K_{jc} = \sqrt{\frac{120\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$

Section 192.712(d)

It is important at the outset to understand that this provision applies to cracks that survive pressure testing. That is separate and distinct from the application to dents. Several aspects of this language demonstrate that the requirements were written based on an incomplete understanding of the science. This language ignores that CVN testing measures the resistance to fracture under impact loading conditions. Pipelines, however, are subjected to quasi-static loads, making the use of CVN values at the lowest temperatures punitively conservative due to a conservative shift in ductile-to-brittle transition temperature between quasi-static (fracture toughness) and dynamic (CVN) loading.

The default toughness value of 120 ft.-lb specified in § 192.712(d)(3)(iii), are not justified. This value is based on erroneous analysis or misinterpretation of information from past research. Specifically, the value of 120 ft-lb comes from PRCI Report No. PR-003-00108 "Fracture Control Technology for Natural Gas Pipelines Circa 2001"[13] where the value was provided as an example beyond which toughness stops being relevant to burst pressure prediction, shifting to plastic collapse behavior.

6. Tool tolerance and predicted failure pressure.

A certain amount of conservatism in the regulations is appropriate; however, §§ 192.712 and 192.632 contain multiple layers of unnecessary conservatism that should be removed so that an operator can apply its engineering judgment when appropriate. In particular, §§ 192.712(e)(1) and 192.632(c)(5) require that an operator explicitly analyze and account for uncertainties, including tool tolerance, in reported assessment results, unless the dimensions of the defect were verified using *in situ* direct measurements.

The current regulations incorporate many layers of conservatism. Accounting for tool tolerance is adding another layer of conservatism to the process that is not required. There is inherent conservatism in fitness for services assessment models established within ASME/ANSI B31G, R-STRENG, and API 579. The regulations then require additional conservatism be applied through § 192.714(d)(2)(iv) and § 192.933(d)(2)(iv), where class safety factors must be considered.

The Associations request that PHMSA provide flexibility through a risk-based engineering evaluation to determine the risk from the specific characteristics of each anomaly and complete repairs based on the risk profile of each anomaly. Current repair requirements broadly prescribe operators to complete immediate, one year and two repairs on anomalies that could remain in the pipeline for 100 years before they were to grow to failure. The Associations request that PHMSA remove the requirement to account for tool tolerances from § 192.712(e)(1) and to incorporate PSQR[14] as an accepted evaluation methodology for metal loss anomalies in § 192.632(a)(2)(ii) and § 192.712(b).

[13] Leis, B.N. et al. "Fracture Control Technology for Natural Gas Pipelines Circa 2001." Pipeline Research Council International (PRCI) Report No. PR-003-00108-R01, 2001.

[14] PSQR stands for Plausible Profile, an alternative method of modeling metal loss (corrosion). PRCI conducted a peer review of PSQR in 2019, PR218-183607-Z01, "Peer Review of the Plausible Profile (PSQR) Corrosion Assessment model" (Sept. 24, 2019).

Estimated Cost Data

The ANPRM requests that operators provide per-unit, aggregate and programmatic (both one-time implementing and recurring data to assist PHMSA in supporting estimates that will accompany a proposed rule. One of the most significant imbalances between compliance costs and safety benefit is related to the requirement to perform unnecessary excavations on anomalies that do not pose a threat to pipeline integrity. These costs include expenses related to excavation and performing the repair, the deployment of human resources (both company personnel and contractors), adverse environmental impacts, including land disturbance and methane emissions, and negative impacts on the efficiency of pipeline operations, including service disruptions to customers.

Many variables can affect the cost of an individual excavation, and the costs associated with an excavation will vary widely. The costs of an excavation range from as little as $90,000 up to a high of almost $2.4 million. While the Associations cannot estimate at this time how many unnecessary anomalies the average operator performs each year, we will endeavor to gather that information to provide during the NPRM stage of the rulemaking when we have the benefit of seeing PHMSA's exact proposed rulemaking language.

ANPRM Question III.A.2.

"Do anomaly repair criteria, remediation timelines, and IM regulations for gas transmission pipelines (part 192, subparts M and O) and hazardous liquid and carbon dioxide pipelines (§§ 195.401 and 195.452(h)(4)) accommodate innovative technologies and methods for the discovery, evaluation, and remediation of anomalies? Are there specific, innovative technologies and methods with significant safety or cost-saving potential that are inhibited by regulations? Please identify any of those innovative technologies and methods, the categories of pipeline facilities (e.g., hazardous liquid transmission pipelines; gas transmission pipelines) that could employ them, the particular regulatory provisions inhibiting their use, and any anticipated compliance cost savings or safety benefits from use of those technologies and methods."

Comments of the Associations on Question III.A.2.

Innovative technologies for discovering, evaluating and remediating anomalies offer safety and other benefits, such as more accurate anomaly sizing and characterization, better prioritization of repairs, and reduced unnecessary excavations. Deployment of these technologies, however, is constrained by prescriptive part 192 repair criteria that impede the ability of operators to deploy engineering critical assessments, probabilistic modeling, and advanced ILI analytics. In addition, the regulations do not account for the improved ability to monitor defect growth rates, predict failure pressure more accurately or to rank anomalies by their actual risk. Below, the Associations provide examples of how existing repair criteria, remediation timelines, and integrity management regulations may impede deployment of innovative technologies.

Section 192.933 defines immediate repair conditions based on fixed conditions, such as depth thresholds or dent characteristics, without regard to data from high-resolution tools, strain-based assessments, or known attributes that may show that an anomaly is stable or non-injurious. These overly prescriptive requirements can discourage use of high resolution EMAT tools which are capable of detecting non-injurious cracks and crack-like features. Moreover, these features may have existed for decades without growth and may have experienced a pressure test at a level sufficient to ensure stability. Section 192.933 requires that the operator treat such features as immediate repair conditions regardless of the anomaly's origin, type, validated stability, or consideration of historical material testing on the pipeline. As a result, an operator cannot effectively prioritize repairs based on known risk, and must perform unnecessary excavations. The Associations request PHMSA allow greater flexibility in how anomalies are reviewed. Additionally, evidence has been provided throughout this document that shows through greater research that required repair criteria can be overly conservative. In multiple responses, it has been shown that a 50% through wall crack can survive for 100 years before growing to failure but it is currently a required immediate repair condition. PHMSA should allow greater engineering judgement and evaluation be used before requiring very prescriptive repair measures.

Reduction in the Use of 192.18 Notifications

In addition, some operators report that PHMSA's § 192.18 notification process slows their ability to deploy innovative technologies, such as the PSQR defect analysis method. When implemented in 2020, § 192.18 was intended to enable operators to use other technology or alternative equivalent technology 91 days after giving PHMSA advance notification, subject to PHMSA's ability to object. In practice, § 192.18 has become an impediment to operators' ability to implement innovative and advanced technologies as PHMSA routinely seeks more time and requests additional information. The result is that operators are delayed in their ability to apply innovative technologies and methods for the discovery, evaluation, and remediation of anomalies for well beyond the 90-day period articulated in the regulation. Operators should be able to implement new technologies or processes since operators are already required to maintain thorough documentation of their procedures and processes and are required to provide sound engineering technical justifications. Operators' procedures, processes, and evaluations are subject to audit and enforcement if PHMSA finds that they do not comply with the regulations.

To alleviate the § 192.18 bottleneck, the Associations recommend that PHMSA provide for conditional or performance-based acceptance of new technologies in order to enable their implementation while maintaining safety oversight. Further, INGAA requests that PHMSA implement a timeline by which the agency must respond or put limitations on reasons they can object to a notification.

In addition, the Associations have found that the requirement in § 192.607(e)(5) that an operator provide advance notification to PHMSA in accordance with § 192.18 before using an alternative sampling method different from the requirements of § 192.607(e)(2) creates unnecessary delays and slows pipe material verification efforts, which could impact an operator's ability to meet the 50% MAOP reconfirmation requirement by 2028 or 100% by 2035, as required by § 192.624 . The Associations recommend that PHMSA amend § 192.607(e)(5) to remove the advance notification requirement for alternative sampling methodologies. Operators are already required to maintain thorough documentation of their pipe material verification efforts and provide sound technical justifications. Operators' procedures, including sampling methods, also are subject to audit and enforcement if PHMSA finds that they do not comply with the regulations.

Acceptance of Other Analytical or Empirical Models to Evaluate Strain in Lieu of FEA

When reviewing some operators' § 192.18 submissions pursuant to § 192.712(c)(11), PHMSA also has stated that only Finite Element Analysis (FEA) can be used to evaluate strain levels required under § 192.712(c)(6) and fatigue life under § 192.712(c)(9). PHMSA's statements are not consistent with the regulations which state that "other technology" or "other analytical methods" are acceptable to meet the requirements in § 192.712(c). Analytical or empirical models have been extensively validated include PRCI Mechanical Damage Assessment Improvements (MD-5-3), PRCI Improve Dent-Cracking Assessment Methods (MD-5-2): The Sky Is not Falling - Mechanical Damage can be assessed Appropriately[15], IPC2024-134138 Strain Assessment Of Pipeline Dents Interacting With Girth Welds Using Finite Element Method[16], IPC2024-133869 Development and Implementation of a Dent Engineering Critical Assessment (ECA) in Accordance with PHMSA's Gas Mega Rule[17], IPC2024-133905 Improvements to B31.8 Dent Strain Estimation and Assessment of Dent Formation Induced Cracking[18], IPC2024-133928 Dent Safe Excavation Pressure and Fracture Reliability Assessment with Machine Learning[19], and IPC2022-87211 Machine Learning-Based Severity Assessment of Pipeline Dents[20]. They provide a higher level of conservatism than a Level 3 FEA. These approaches are based on sound engineering practices and should be acceptable when evaluating dent's critical strain and fatigue lives.

Recommended CVN and Alternative Toughness Values

The Associations also recommend that operators be permitted to use material testing methods other than Charpy v-notch in fracture mechanics models without having to provide a § 192.18 notification to PHMSA or obtain a special permit. As explained above in its response to Question III.A.1, the toughness values in § 192.712(d)(3)(iii) and § 192.712(e)(2)(i)(C) and (D) are not consistent with the current state of science in fracture mechanics. Operators should be permitted to use more appropriate CVN and toughness values reflected in PRCI's report entitled "PR276-223814-R01 Pragmatic Application of MegaRule RIN 1 - 192.712 Toughness Values" or use the processes defined in "PR-276-223814 Pragmatic Application of MegaRule RIN 1 - 192.712 Toughness Values L2 and L3 Procedures" when more information is known about the material.
The research provides three levels of analysis dependent upon the known material characteristics and material specific fracture behavior. Level 1 is the simplest and is a very conservative method given the lack of data. These values are shown below. These values could be used in place of the

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[15] Rana, A. et al, "The Sky Is not Falling - Mechanical Damage can be assessed Appropriately", Pipeline Pigging & Integrity Management (PPIM) Paper, 2025.

[16] Sun, J. et al, "Strain Assessment Of Pipeline Dents Interacting With Girth Welds Using Finite Element Method", International Pipeline Conference (IPC) Paper Number IPC2024-134138, 2024.

[17] Tang, H. et al. "Development and Implementation of a Dent Engineering Critical Assessment (ECA) in Accordance with PHMSA's Gas Mega Rule", International Pipeline Conference (IPC) Paper Number IPC2024-133869, 2024.

[18] Tang, H. et al. "Improvements to B31.8 Dent Strain Estimation and Assessment of Dent Formation Induced Cracking," International Pipeline Conference (IPC) Paper Number IPC2024-133905, 2024.

[19] Tang, H. et al. "Dent Safe Excavation Pressure and Fracture Reliability Assessment with Machine Learning", International Pipeline Conference (IPC) Paper Number IPC2024-133928, 2024.

[20] Tang, H. et al. "Machine Learning-Based Severity Assessment of Pipeline Dents", International Pipeline Conference (IPC) Paper Number IPC2022-87211, 2022.

existing 192.712(e)(2)(i) and could be used to meet the requirements 192.712(e)(2)(i)(A). Operators should be able to utilize more pipe specific values from industry databases or newer research to assist in obtaining values that meet the requirements of 192.712(e)(2)(i)(A).

Charpy Upper-Shelf Energy	All base metals & modern seam welds and HAZ's	Vintage DSAW exhibiting ductile behavior at operating temperatures	Vintage LF-ERW/EFW exhibiting ductile behavior at operating temperatures	Vintage DC-ERW exhibiting ductile behavior at operating temperatures	Current 192.712(e)(2)(i) body values	Current 192.712(e)(2)(i) seam values
Value with no prior failures on the pipeline	19.0 ft.-lbs.	19.0 ft.-lbs.	17.0 ft.-lbs.	9.0 ft.-lbs.	13.0 ft.-lbs.	4.0 ft.-lbs.
Value used on a pipeline with a previous failure	14.0 ft.-lbs.	14.0 ft.-lbs.	12.0 ft.-lbs.	4.0 ft.-lbs.	5.0 ft.-lbs.	1.0 ft.-lbs.

Only a small percentage of the data examined had cases where non-ductile (brittle) initiation was predicted for vintage DC/LF-ERW/EFW fusion line and DSAW deposited weld metals. There is a range of toughness even with brittle initiation behavior determined from a procedure called the Master Curve or Reference Toughness Curve, but since there is no data on this material, the lower-shelf toughness of the material-specific Reference Toughness Curve was used, giving results similar to the recommendation from the MAT-8 User Guide.

Report PR-276-223814 Pragmatic Application of MegaRule RIN 1 - 192.712 Toughness Values L2 and L3 Procedures provides a Level 2 evaluation that can be used when the operator has Charpy data for the materials in their line. The Charpy data may only be at one temperature and may be from subsize specimens. From this data, procedures are given to take that single temperature data, account for specimen size, and assess if the material will have ductile initiation behavior for the thickness of the pipe with a bounding axial surface-crack size. With ductile-initiation behavior, the upper-shelf toughness can be used in certain burst pressure predictive analyses. The Charpy energy at the minimum operating temperature or testing temperature would be too conservative in these cases. The operator can use a Level 3 evaluation when the operator has more detailed fracture mechanics data.

PHMSA should clarify that other toughness factors can be used in place of CVN values. The "PR276-223814-R01 Pragmatic Application of MegaRule RIN 1 - 192.712 Toughness Values" report also provides other equivalent initiation fracture toughness calculations that are used in other models. The table below shows the calculations used to conservatively determine fracture toughness for Level 1 evaluations when the pipeline material characteristics are unknown. This level has greater conservatism than the other levels where data is known. These equations can be used to generate fracture toughness values that could be used in place of the existing

192.712(e)(2)(i) CVN values and could be used to meet the requirements 192.712(e)(2)(i)(A). Operators could use more pipe specific values or newer research to assist in obtaining values that meet the requirements of 192.712(e)(2)(i)(A).

Recommended K_{Jc} for $K_{Jc}/_{Jc}$ based burst pressure models (psi-in$^{0.5}$)	**All base metals & modern seam welds and HAZ's**	**Vintage DSAW exhibiting ductile behavior at operating temperatures**	**Vintage LF-ERW/EFW exhibiting ductile behavior at operating temperatures**	**Vintage DC-ERW exhibiting ductile behavior at operating temperatures**
Value with no prior failures on the pipeline	$K_{jc} = \sqrt{\frac{570\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$	$K_{jc} = \sqrt{\frac{570\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$	$K_{jc} = \sqrt{\frac{510\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$	$K_{jc} = \sqrt{\frac{270\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$
Value used on a pipeline with a previous failure	$K_{jc} = \sqrt{\frac{420\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$	$K_{jc} = \sqrt{\frac{420\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$	$K_{jc} = \sqrt{\frac{360\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$	$K_{jc} = \sqrt{\frac{120\left(0.9-\frac{a}{t}\right)E}{(1-v^2)}}$

Crack Non-Destructive Examination (NDE) Technologies

Finally, while operators have validated the ability of Eddy Current technology to rapidly screen pipelines for surface breaking linear indications, PHMSA-sponsored studies[21] and multiple legacy industry standards[22] incorporated by reference into part 192 specify the exclusive use of magnetic particle inspection to screen pipelines for stress corrosion cracking. The Associations recommend that PHMSA permit the use of Eddy Current technology to eliminate redundant inspection and increase the speed at which inspections can be performed. Work is ongoing in AMPP/ NACE to update applicable standards such as NACE SP 0204, for SCC DA, to include technological advances such as Eddy Current technology. The Associations recommend adoption of the revised NACE SP when it is completed.

The Associations want to confirm with PHMSA that an operator or contractor can use Eddy Current technology today for identifying and sizing cracking, as an alternative to magnetic particle inspection. There is nothing in the regulations that preclude its use outside of stress corrosion cracking (SCC) direct assessment (DA) in an excavation to identify possible cracking. API RP 1176 does recognize Eddy Current technology for cracking.[23] The Associations recommend that PHMSA incorporate API RP 1176.

[21] U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, "Stress Corrosion Cracking Study, Chapter 6 - Detection of SCC," Michael Baker Jr., Inc., OPS TTO8 Final Draft (October 12, 2004), https://primis.phmsa.dot.gov/docs/sccReport/CHAPTER%206%20-%20DETECTION%20OF%20SCC.PDF
[22] ANSI/NACE SP0502-2010, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology" (revised June 24, 2010); NACE SP0204-2008, Standard Practice, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology" (reaffirmed Sept. 18, 2008).
[23] API RP 1173, section 10.7.4.

ANPRM Question III.A.3.

"PHMSA's risk-based IM regulations for gas transmission pipelines (Part 192, Subpart O) and hazardous liquid and carbon dioxide pipelines (§ 195.452(h)(4)) include specific thresholds for particular anomaly types and mandated remediation timelines in a manner consistent with traditional, prescriptive regulatory frameworks. Does that incorporation of traditional, prescriptive elements within PHMSA's risk-based IM regulations yield safety benefits commensurate with the associated reduction in regulatory flexibility and increase in compliance costs to operators? Are there risks associated with prescribed repair conditions and remediation timelines, such as personnel safety and site environmental damage due to repair activity or lost product associated with maintenance-related blowdowns and evacuation? Should PHMSA consider amending any particular provisions in its IM regulations for gas transmission pipelines (Part 192, Subpart O) and hazardous liquid and carbon dioxide pipelines (§ 195.452) to strike a more appropriate balance between safety benefits and compliance costs? Please identify any specific regulatory amendments that merit consideration, as well as the technical, safety, and economic reasons supporting those recommended amendments."

Comments of the Associations on Question III.A.3.

The Associations acknowledge that prescriptive repair criteria thresholds and remediation timelines are beneficial in certain circumstances, such as establishing certain thresholds for requiring anomaly response and repair. In other circumstances, the ability to collect additional information or apply advanced analytics are needed in order to properly prioritize anomaly response schedules. The Associations believe that the regulations can reflect both approaches, as long as operators are provided flexibility to select the most appropriate options based on site-specific circumstances, available data and history, and resource constraints.

Inflexible criteria and timelines can constrain an operator's ability to apply validated engineering analysis and advanced analytics to prioritize repairs based on the actual risk posed by a specific threat. For example, with respect to cracks and crack-like anomalies, § 192.933(a)(1)(ii) requires operators to calculate failure pressure in accordance with § 192.712. The results are then used to establish how an operator schedules a remediation response under §§ 192.933(c) and § 192.933(d), which describes immediate repair conditions. The prescriptive requirements of § 192.933 are appropriate for true crack flaws where a fracture mechanics approach is applicable and rupture failure is predominantly governed by hoop stress.

In contrast, the responses to other types of crack-like anomalies, such as circumferentially oriented cracking and manufacturing flaws (i.e., lack of fusion in the longitudinal seam weld), should not be prescriptive. Circumferential cracks are affected by stresses that are perpendicular to the hoop stress and cannot be managed like axial cracks. For lack of fusion flaws and hook cracks, fracture mechanics models are typically overly conservative because the radius at the root of the flaw is relatively large compared to true cracks. Thus, alternative analytical methods are more appropriate for assessing the criticality of these types of crack-like defects. In these circumstances, an operator should be permitted to use an engineering assessment to determine the appropriate response. The Associations believe that this approach is consistent with safety and will minimize operational impacts and environmental disturbances associated with excavations.

In addition, as explained above in response to Question III.A.1, the 50 percent metal loss threshold requiring repair of crack-like anomalies exceeds the margin of safety needed to protect pipeline integrity. Operators should be allowed to evaluate and assess a crack-like anomaly using accepted engineering analyses to determine the appropriate remedial response. Operators also should have flexibility to evaluate and assess crack-like anomalies to determine if they are stable manufacturing or construction defects.

The Associations request that § 192.714(d)(1)(ii) and § 192.933(d)(1)(ii) remove the requirement to immediately repair a dent with metal loss and that § 192.714(d)(2)(iii) and § 192.933(d)(2)(iii) remove the requirement to repair a dent within 2 years with metal loss on the lower 1/3 of the pipe if the dent meets the criteria provided by ASME B31.8-2018 and the metal loss repair requirement provided for class 1 in § 192.714(d)(2)(iv) of "1.1 times MAOP, an operator must follow the remediation schedule specified in ASME B31.8S, section 7, Figure 7.2.1-1, as specified in <u>paragraph (c)</u> of this section". B31.8-2018, section 851.4.1, allows plain dents to remain in service if the dent does not exceed 6% nominal pipeline diameter and if corrosion is present, the calculated failure pressure from metal loss is less than the MAOP of the pipeline or the dent does not exceed 2% nominal pipeline diameter at a ductile girth or long seam weld. Dents that do not meet the B31.8-2018 851.4.1 and referenced § 192.714(d)(2)(iv) criteria would be evaluated through the proposed § 192.712(c) ECA process to determine if a repair is necessary. The code should also allow proactive applicable dent repair and bypass the dent evaluation process if the pipeline needs to be returned to service in a timelier manner.

The Associations recommend that the regulations be amended in appropriate areas to allow an operator to rely on innovative and advanced assessment technologies to manage and prioritize anomaly repair response. Advancements in pipeline safety technology promote safety while also promoting efficient use of resources, reducing adverse impacts (including environmental disturbance and releases of methane) associated with unnecessary excavation, and minimizing operational impacts. Taking this next step in the evolution of pipeline safety is consistent with the performance-based integrity management paradigm that PHMSA initiated decades ago.

In addition, more generally, the Associations suggest that PHMSA also consider other changes to Part 192 including potentially restructuring Part 192 to offer both a performance-based track and prescriptive track; discontinuing the dual approach (class location vs. HCA/MCA) for measuring consequences of pipeline failure and consolidating them into a single approach, consolidating repair criteria for HCA and non-HCA pipeline segments, and addressing differences between ASME B31.8S and Part 192.

<u>ANPRM Question III.A.4.</u>

"Is it appropriate for repair timelines to begin on the date of ''discovery'' of anomalies on gas transmission (§§ 192.714(d) and 192.933(b)) and hazardous liquid and carbon dioxide pipelines (§§ 195.401(b)(1) and 195.452(h)(2))? How do operators of those pipelines determine the moment of discovery? Should PHMSA consider amending any particular regulatory provisions to improve the clarity or practical implementation of its regulations regarding when a remediation obligation attaches? Please provide the technical, safety, and economic justifications for any suggested revisions."

Comments of the Associations on Question III.A.4.

PHMSA's pipeline anomaly repair criteria and remediation timelines for onshore gas transmission pipeline segments located outside of HCAs and within HCAs are set forth in § 192.714 (non-HCA pipeline segments) and § 192.933 (HCA pipeline segments), respectively. Implementing the requirements of these sections is triggered when an operator "discovers" a condition that requires remediation. The "discovery of a condition" is further defined by §§ 192.710(e) and 192.933(b), which provides that an operator has 180-days, absent demonstration to PHMSA that 180 days is not practical, to obtain "adequate information" to complete an integrity assessment on a condition that poses a potential threat to the integrity of the pipeline.

For HCA pipeline segments, § 192.933(b) requires notification and no objection from PHMSA, pursuant to the § 192.18 process, if the 180-day period for obtaining adequate information is not practical. Such notice and approval to demonstrate the same constraints is not required for non-HCA segments under § 192.710(e). Taken together, the requirements of these regulations impose unnecessary redundancies and create inefficiencies.

The regulations do not specify what constitutes "adequate information," but they do require operators to remediate anomalous conditions on defined schedules pursuant to §§ 192.714 and 192.933 once such information has been obtained (not to exceed 180-days absent a showing of impracticability, and approval from PHMSA of such showing when in an HCA). As such, the date of discovery, triggered once adequate information is obtained, is vitally important for regulatory compliance regarding remediation of anomalous threats within the requisite timeframe. The absence of clear regulatory language on this triggering event has led to ambiguity and uncertainty in the industry about PHMSA's expectations regarding the start date for remediating anomalous conditions. This, in turn, has led to disparate processes in the industry for when "discovery" occurs, and disparate treatment across PHMSA's regional offices in enforcement against compliance with repair timelines.

PHMSA's guidance to the industry on what constitutes adequate information for purposes of discovery of a condition is found in PHMSA's Gas Transmission Integrity Management FAQ 58, which provides as follows; "Discovery of a condition occurs when an operator has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline. Depending on circumstances, an operator *may have adequate information when the operator receives the preliminary internal inspection report, gathers and integrates information from other inspections, or when an operator receives the final internal inspection report*. Operators are required to obtain sufficient information about a condition to make this determination no later than 180 days after an integrity assessment, unless the operator can demonstrate that the 180-day period is impractical." (emphasis added). This FAQ introduces additional uncertainty as it provides that an operator may be on the regulatory clock for remediation repairs when it receives a preliminary inspection report OR a final inspection report from an ILI vendor; two very different dates in time.

Further, the ambiguity has led to difficulties in implementing the regulation. Operators often interpret "discovery" as the point at which sufficient information is available to determine that a condition presents a potential threat to pipeline integrity, not merely the initial detection of an anomaly. This ambiguity can and has led to inconsistent application and compliance challenges.

Specifically, the Associations recommend that PHMSA revise §§ 192.710(e) and 192.933(b) to clarify that the date of discovery is when engineering analyses are completed to properly characterize the severity of the anomaly. PHMSA should consider amending the relevant provisions to explicitly define "discovery" as the point at which an operator has received a final report or preliminary report containing immediate repair conditions from the ILI vendor, completed the necessary analysis of all information to confirm if conditions identified in the report meet repair criteria, and completed the process of integrating the appropriate data for engineering analysis for all of the conditions identified. Such clarity would improve regulatory consistency and fairness and align with the intent of ensuring safety while recognizing the technical and logistical realities of anomaly assessment. A clearer definition would also support better planning and prioritization, allowing operators to allocate resources based on actual risk rather than arbitrary timelines.

ANPRM Question III.A.5.

"Are there any PHMSA interpretations addressing its anomaly repair criteria, remediation timelines, and IM regulations for gas transmission pipelines (part 192, subparts M and O) and hazardous liquid or carbon dioxide pipelines (§§ 195.401 and 194.452(h)(4)) impose unjustified compliance costs for different categories of pipeline facilities? If so, which categories of pipelines facilities, and what are those associated compliance costs? Are there any interpretations of PHMSA anomaly repair criteria, remediation timelines, and IM regulations that merit codification in parts 192 or 195 regulations? Please identify any specific regulatory amendments that merit consideration, as well as the technical, safety, and economic reasons supporting those recommended amendments."

Comments of the Associations on Question III.A.5.

PHMSA interprets Part 192 regulations, including anomaly repair criteria, remediation timelines and integrity management regulations in final orders, letters of interpretation, frequently asked questions, advisory bulletins, inspection guidance, etc. There have been circumstances where PHMSA's interpretations are either inconsistent with regulatory text or are counterproductive to the objective of the regulation. In addition, during audits, many operators have encountered different regulatory interpretations across the regions and PHMSA inspectors who seek to impose requirements that either exceed, or are inconsistent with, the regulatory language. PHMSA inspectors have indicated that the PHMSA training had provided them with a different regulatory interpretation than the regulatory language approved from GPAC, the preamble of the final rule, or other PHMSA documentation. PHMSA should ensure consistency in regulatory interpretation from regulatory creation through implementation and training on regulations.

Below, the Associations identify regulatory interpretations that are counterproductive to achieving compliance or that impose compliance costs that are out of balance with resulting safety benefits should be removed or modified.

1. FAQ-23 of the RIN 1 Batch-1 FAQs should be removed.

On September 15, 2020, PHMSA issued Frequently Asked Questions for its Gas Transmission Final Rule (RIN-1) published in the Federal Register on October 2, 2019.[24] FAQ 23 states the following:

> **FAQ-23. Is there a process to compile comparable pipe materials properties across the industry?**
> No process currently exists to compile pipe material property information. Material properties can vary greatly during the manufacturing process. PHMSA expects operators to verify pipe material used within their system.

The Associations recommend that PHMSA remove FAQ-23 because it is counterproductive to the goal of improving operators' data quality and efforts to validate pipe material properties. There are scenarios where sufficient information is available to conclude that pipe materials are consistent or the same across multiple pipelines. As long as material properties meet the requirements of a population (as defined in the code), an industry-wide database can be helpful because it enables operators to leverage information among each other in their efforts to validate pipe material data in their systems.

2. PHMSA should clarify that an operator has up to ten years to perform an assessment on a newly activated threat identified in a covered segment.

Section 192.939 sets forth reassessment intervals for pipeline segments covered under integrity management and establishes the maximum assessment interval as seven calendar years. Section 192.939 does not address whether an operator may establish separate assessment intervals for newly activated threats (*i.e.*, threats that, through continual evaluation of potentially applicable threats, an operator identifies data suggesting that an integrity assessment for that threat is needed), in a given covered segment. In 2021, however, PHMSA issued a letter of interpretation stating that an operator must assess a newly activated threat within the same assessment cycle as previously identified threats within the covered pipeline segment, regardless of when the threat became activated.

> PHMSA's Interpretation Letter PI-21-0004 states the following:
> Section 192.939 does not have an exception for newly discovered threats within existing HCAs if they are discovered within an assessment cycle. Therefore, a pipeline operator must assess a newly activated threat on a covered segment within the same assessment cycle as other threats that were previously identified through risk assessment under 49 CFR § 192.917(a) regardless of when the threat becomes active. PHMSA recognizes that an operator may not be able to comply with the

[24] Frequently Asked Questions (FAQ) for the Final Rule titled, "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," published on October 1, 2019 (Sept. 15, 2020).

> requirements stated in 49 CFR § 192.939 in limited instances, in which case PHMSA may allow a waiver from a reassessment interval required by 49 CFR § 192.939 if the waiver would not be inconsistent with pipeline safety. Those limited instances include where an operator cannot obtain the internal inspection tools within the required reassessment period, and where the operator cannot maintain local product supply if it conducts the reassessment within the required interval.

Section 192.943 describes how to seek a waiver if one of these conditions applies.[25]
The Associations disagree with this Interpretation Letter and believe it unnecessarily complicates anomaly assessments without generating meaningful safety benefit. The Associations recommend that this letter of interpretation be withdrawn. Sections 192.919 and 192.921 reflect a more appropriate approach for completing a baseline assessment for newly activated threats.

The following example illustrates the challenges associated with PHMSA's Letter of Interpretation. An operator determines that a covered pipeline segment is susceptible to hard spots after the operator incorporates the results of a recently released study into its integrity management plan. Section 192.919(a) requires that the operator update its baseline assessment plan and § 192.919(b) requires that the operator select a methodology to perform a baseline assessment. After considering all risk factors for each covered segment in the pipeline system, the operator determines an appropriate schedule for performing a baseline assessment for hard spots in accordance with § 192.919(c).

Subpart O does not directly address the maximum interval required for completing the baseline assessment of the newly activated threat in an existing HCA. However, guidance may be gleaned under other regulations. Specifically, § 192.921(f) provides an operator up to ten years from the date a new HCA is identified to complete a baseline assessment. Section 192.921(g) allows an operator ten years to complete a baseline assessment for a newly installed segment of pipeline.
A newly activated threat on a covered pipeline segment is analogous to a newly identified HCA and newly installed pipeline segment. Identifying a newly activated threat in an existing HCA presents a comparable risk profile to a newly identified (unassessed) threat that may be discovered in a newly discovered HCA. The Associations believe that an operator should be permitted up to 10 years to assess that newly activated threat.

The Associations request that PHMSA withdraw its Letter of Interpretation Letter, PL-21-0004. In addition, to provide regulatory clarity, the Associations request that PHMSA amend § 192.921(f) as follows:

> **(f) Newly identified <u>threats or</u> areas.** When an operator identifies a new high consequence area (see § 192.905)<u> or a new threat in an existing high consequence area (see § 192.917)</u>, an operator must complete <u>a threat-specific</u> ~~the~~ baseline assessment<u>s</u> of the line pipe ~~in the newly identified high consequence area~~ within ten (10) years from the date the area <u>or threat</u> is identified.

[25] Letter of John A. Gale, Dir. Office of Standards and Rulemaking, PHMSA, to Ms. Christine Cowsert, VP, Gas Asset Mgmt. & System Operations, Pacific Gas & Electric Co., PI-21-0004 (June 23. 2021).

3. *PHMSA should clarify that § 192.714 applies only to pipeline segments required to be assessed under § 192.710.*

Section 192.710 requires that an operator performs assessments of non-HCA pipeline segments that have MAOPs greater than or equal to 30% of SMYS and that lie in either a Class 3 or Class 4 location or a moderate consequence area if the pipeline segment can accommodate an inspection with an ILI tool. Section 192.714, in turn, sets forth the repair criteria applicable to anomalies discovered as a result of assessments performed on non-HCA pipeline segments. Some operators have reported ambiguity with respect to whether the §192.714 repair criteria apply to pipelines not required to have a §192.710 assessment. The Associations request that PHMSA clarify that §192.714 applies only to pipeline segments that must be assessed under §192.710.

4. *PHMSA should clarify that certain pipelines are not susceptible to manufacturing and construction threats.*

Sections 192.710(c) and 192.921(a) require that an operator assess the integrity of pipeline segments by using one or more of the listed assessment methods for each threat to which the pipeline segment is susceptible. The meaning of the term "susceptible" is not defined in the regulations. Some operators have encountered PHMSA auditors who have stated that an operator is required to perform certain assessments because the operator did not have sufficient information to rule out a particular threat. This is particularly true for pipelines containing stable manufacturing threats where the pipe is subject to overlapping MAOP reconfirmation requirements for HCAs, MCAs, and Class 3 and 4 locations.

The Associations believe that operators should be permitted to determine that a pipeline is not susceptible to certain manufacturing and construction threats if the MAOP of the pipeline segment is less than 30% SMYS. In these circumstances, the failure mode is likely to be a leak. The ability to prioritize assessments in this way would allow operators to allocate resources to focus on pipelines operating at higher hoop stress levels which present greater safety risk.

5. *PHMSA should clarify excavation requirements when performing internal corrosion direct assessment.*

Section 192.927 describes the process to be followed if an operator performs internal corrosion direct assessment (ICDA). Section 192.927(a) defines ICDA as follows:

> a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas.

As explained below, the Associations request that PHMSA amend the definition of ICDA as follows to be consistent with how the ICDA process works and to facilitate its effectiveness in detecting internal corrosion:

> a process an operator uses to identify and examine areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may first reside, and where internal corrosion is most likely to exist. The process then requires ~~focuses~~ additional direct examinations at ~~on the~~ downstream locations ~~in covered segments~~ which may have the potential to accumulate fluids. The ICDA process allows inferences to be made about the integrity of the entire ICDA Region, to include any High Consequence Area segments. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas.

PHMSA has allowed the use of ICDA since adopting IM over 20 years ago. NACE SP0206,[26] which is incorporated by reference into Part 192, defines how to establish ICDA regions. The Associations' recommendation reflects the ICDA process which is based on thermodynamics, not the location of populations along the pipelines (*i.e.*, HCAs). Specifically, The thermodynamics of fluid flow (gas & liquid) within a pipeline determines the critical angle and the physical location of a critical angle is largely determined by terrain, not population or the location of HCA covered segments. The Associations do not object to the requirement that detailed examinations be performed in covered segments. However, recent amendments to § 192.927 limit the effective use of ICDA process.

Section 192.927(c)(3), which was adopted in 2022 as Part of the Gas Transmission Rule,[27] describes the requirements for performing a "detailed examination" of a covered pipeline segment. Under § 192.927(c)(3), when first using ICDA for a covered segment, the operator must identify at least two locations for excavation within each covered segment associated with the ICDA region and perform a detailed examination for internal corrosion at each location. One of the dig locations must be the low point within the covered segment nearest to the beginning of the ICDA region and the second dig location must be further downstream within the covered segment near the end of the ICDA region.

PHMSA should clarify that one detailed examination must be conducted at the first critical inclination angle (e.g., sag, drip, valve, manifold, dead-leg) in the ICDA region, in accordance with NACE SP0206. If no critical angles exist in the ICDA region, the detailed examination must be conducted at the largest angle of inclination in the ICDA region.

The basis for this recommendation is that the ability of flow modeling to predict areas most likely to hold liquid and experience internal corrosion is not related to the locations of covered segments. The requirement in § 192.927(c)(3) that a low spot be located in an HCA has no technical or safety basis. The result is to arbitrarily limit the use of ICDA or force an operator to expand the limits of a covered segment to allow for the use of ICDA.

An operator also should be required to perform the second detailed examination at the next downstream location most likely to hold liquids. Additional digs would be conducted at

[26] NACE SP0206-2006, Standard Practice, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)" (approved Dec.1, 2006).
[27] 87 Fed. Reg.52,224 at 52,275.

downstream locations, most likely to hold liquids until two consecutive locations are identified with no internal corrosion.

Section 192.927's requirement that a minimum of two (2) ICDA detailed examinations be conducted within each covered segment in the ICDA region, regardless of whether ICDA modeling identifies areas with the covered segment as being likely to hold liquids does not serve a safety purpose and results in unnecessary excavations.

In *INGAA v. PHMSA* which sought review of the Part II Gas Transmission Rule issued August 22, 2022, PHMSA conceded that the term "covered segment" and "SCC segment" mean the same thing. In its decision, the court acknowledged this and stated, "PHMSA indicated in the record that it viewed the two terms as interchangeable. At oral argument, INGAA's counsel accepted that, if "SCC segment" and "covered pipeline segment" mean the same thing, it has no disagreement with the agency or the final rule. Accordingly, we take PHMSA at its word and interpret the final rule as substantively the same as the proposed rule with respect to the number of excavations required for a direct assessment."[28] PHMSA should implement this approach across all direct assessments and memorialize this decision within the code, clarify the definition of covered segment, or develop a new defined term to address a "direct assessment segment".

<u>ANPRM Question III.A.6.</u>

"Gas transmission, hazardous liquid, and carbon dioxide pipelines are not all identical and may merit distinguishable regulatory requirements regarding the discovery, evaluation, and remediation of anomalies. Are there substantive differences in the characteristics (e.g., pipeline capacity or size; physical processes) of and among the different categories of gas transmission and hazardous liquid or carbon pipelines justifying distinguishable anomaly repair and IM requirements? In light of those differences, what, if any, amendments to PHMSA parts 192 and 195 regulations governing anomaly repair criteria, remediation timelines, and IM would be appropriate, and what would be the avoided practicability challenges, compliance costs, or safety impacts from such amendments?"

<u>Comments of the Associations on Question III.A.6.</u>

The Associations agree that there are substantive differences in the characteristics of the different types of pipelines - gas transmission, hazardous liquid, and carbon dioxide - that justify different regulatory requirements in certain specific instances, but not all. However, there is also significant overlap in how operators of gas transmission and hazardous liquid pipelines evaluate, monitor, and make repair decisions on anomalies on their respective systems that warrant regulatory neutrality and consistency with respect to foundational regulatory requirements for repair criteria, remediation timelines, and application of integrity management principles. Similar criteria for all

[28] *Interstate Natural Gas Association of America v. PHMSA*, 114 F.4th 744, 756 (D.C. Cir. Aug. 16, 2024).

pipelines related to discovery, evaluation, and remediation of anomalies would be beneficial to operators that have both Part 192 and Part 195 pipelines.

Question III.A.6 highlights the value of implementing a risk-informed or risk-based approach to pipeline safety regulations and operations. Operators of both gas and hazardous liquid pipelines can utilize a risk-based approach to both pipeline types. This would allow for the evaluation of the type of product being transported, pressure cycling data by pipeline system segment, MAOP and SMYS, diameter, wall thickness, seam type, and other specific material and operating characteristics to make better decisions on repair timing. Additionally, some operators have built a long history of ILI data and possible pressure test data on pipeline systems that cannot be considered under the existing repair requirements. Having a risk-based approach would allow more data to be considered in making decisions versus a prescriptive requirement that does not allow this dataset to be considered.

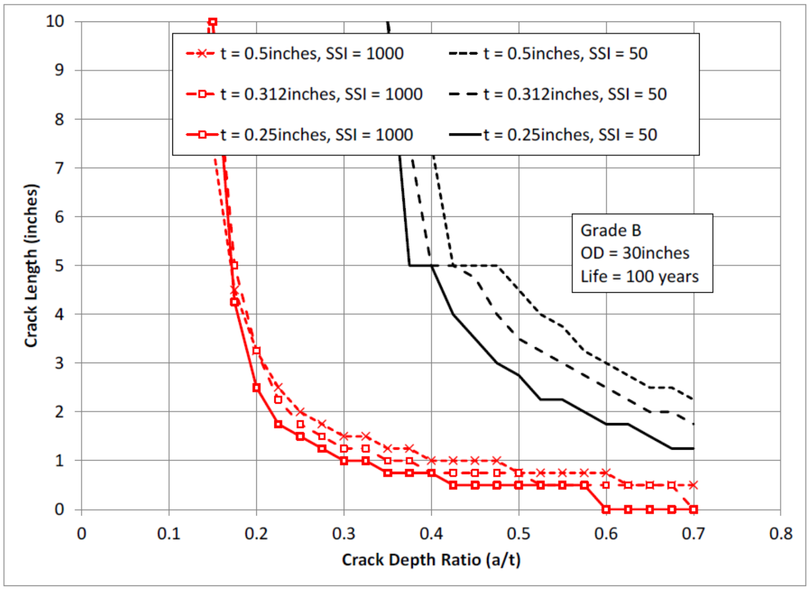
The Associations recommend keeping prescriptive criteria neutral as it relates to differences in diameter, wall thickness, and commodity transported to the extent already incorporated in the regulations and as proposed to be modified in these comments. The Associations further recommend introducing an alternative path to compliance to allow for a performance-based approach where such differences can be accounted for as part of the risk and fitness-for-service assessment (see Associations' response to Question III.A.3).

One key difference between gas and hazardous liquid lines is the level of fatigue cycling, which contributes to the enlargement of crack-like defects and potential leaks in dents. Cyclic fatigue levels on gas pipelines are typically not a significant risk factor.[29] In place of the prescriptive repair requirements of § 192.714 and § 192.933, and the evaluation requirements of § 192.712(d) and § 192.917(e)(2), the Associations propose utilizing a conservative evaluation process to determine which cracks are safe to remain in service and which cracks require a more thorough fatigue analysis, as proposed in the BMT Fleet Technologies document, "Fatigue Considerations for Natural Gas Transmission Pipelines"[30]. The document proposed a Fatigue Susceptibility Rapid Assessment process that found key drivers in crack growth. Those key drivers were crack depth, crack length, wall thickness, and the number of cycles the pipeline experiences. Following the Fatigue Susceptibility Rapid Assessment provides a quick conservative evaluation to determine if a crack requires further analysis to determine if a repair is needed or if the crack is safe to remain in service.

As shown in the figures below, applying the same fatigue cycling criteria to both treating gas and hazardous liquid pipelines is inappropriate for certain defects that are subject to different operating conditions and thereby pose different risk levels. Typically, liquid pipelines systems experience greater cycles. An example of a method of being able to assess and compare the cyclic severity of a pressure time history is through the use of a Spectrum Severity Indicator (SSI). One example of an SSI is to calculate the number of cycles of a given pressure range required to grow a crack the same amount as the actual pressure time history over one year. The figure below conservatively

[29] Kiefner & Associates, Inc., "Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines," Final Report No. 05-12R (Apr. 26, 2007).
[30] BMT Fleet Technology, "Fatigue Considerations for Natural Gas Transmission Pipelines," Reference: 30348.FR (Rev. 01) (June 29, 2016).

shows that a pipeline that has 1000 SSI cycles (e.g., liquid pipeline), could have a 30% deep crack that is 1 inch in length and have 100 years before the crack would grow to failure. Similarly, the same pipe that experiences 50 SSI cycles (e.g., natural gas pipeline) could have nearly a 70% deep crack and be 1 inch in length and have 100 years before the crack would grow to failure.



The Associations recommend that requirements to perform fatigue analyses on crack-like indications be removed from §§ 192.712(d)(2) and 192.917(e)(2).

ANPRM Question III.A.7.

"What types of temporary and permanent repair methods do operators of gas transmission, hazardous liquid, and carbon dioxide pipelines use to comply with PHMSA's anomaly repair criteria, remediation timelines, and IM requirements? What percentage of repairs are completed using each type of repair method and for which types of anomalies? Do operators employ consensus industry standards or recommended practices (e.g., the acceptable remediation methods listed in tables 451.6.2(b)–1 and 451.6.2(b)–2 of ASME B31.4–2006) when determining the appropriate repair method for different types of anomalies or categories of gas and hazardous liquid or carbon dioxide pipelines? What is the average cost of each of those repair methods as applied to different types of anomalies or categories of gas transmission, hazardous liquid, or carbon dioxide pipelines?"

Comments of the Associations on Question III.A.7.

The Associations' members employ diverse repair methods based on anomaly types, operational conditions, and risks. This array of best practices is built on decades of field experience and guided by established industry standards. These methods also vary for temporary versus permanent repairs. The Associations request that PHMSA preserve and enhance flexibility in repair method selection and establish a pathway for innovative technologies and techniques. Based on decades of operational experience, the Associations request that PHMSA provide flexibility in the selection and use of proven repair methods, consistent with industry standards, based on the unique operational characteristics of the relevant pipeline facility.

The following methods are commonly utilized by the Associations' members. For permanent repairs, members typically use grinding, sanding, Type B sleeves, compression sleeves, composite sleeve/wrap, bolt-on clamp (with seals), force screw lamp clamp, hot tapping, and pipe replacement.

For temporary repairs, the Associations' members use Type A sleeves, and composite sleeve/wrap (in certain situations).

Regarding the type of anomaly associated with the repair method selected, the Associations' members use the following:

- Corrosion and moderate pitting are typically repaired with a Type B Sleeve or composite wrap.
- Deep Pitting is typically repaired with Type B Sleeve or Pipe Replacement.
- Dents are typically repaired with a Type B Sleeve, Composite Wrap, or Bolt-On Clamp.
- Cracks are typically repaired by sanding or with a Type B Sleeve, Composite Wrap, or Pipe Replacement.

Regarding the approximate percentage of time a particular repair method is used for a specific anomaly, the Associations' members report using the following:

- Leak Clamps (.5%) (Corrosion); Composite Sleeves: (6.5%) (Corrosion); Welded Sleeves: (31.5%) (Cracks, Corrosion, SW Anomalies); Pipe Replacements: 12.5% (Cracks, Corrosion, SW Anomalies).
- Pipe Body Cracks: 80% sanding, 10% compressive "A" sleeve, 10% pipe replacement
- Seam Weld Anomalies: 2% cutout, 10% sanding, 20% compressive "A" sleeve, 68% carbon fiber wrap[31]
- Hardness Anomalies: 10% carbon fiber wrap, 10% compressive "A" sleeve, 80% pipe replacement
- Metal Loss: 90% composite wrap or Type B sleeve (when fails RSTRENG), recoat when passes RSTRENG. 10% cut out and replace pipe segment when fails RSTRENG
- Dents: Composite wraps when repair is required. Cutouts are rare.

This data demonstrates that operators successfully manage diverse repair scenarios through risk-based decision-making. Operators rely on their operational experience and knowledge of their pipeline systems to decide what repair method will provide the greatest safety outcome. For example, welded steel sleeves and fiber reinforced composites are commonly used by pipeline operators to restore the pipeline integrity in compliance with PHMSA's repair requirements because this method avoids having to replace the pipeline segment, has other significant operational, safety, and environmental risks.

[31] The Associations note that most repairs on seam weld anomalies are manufacturing defects. This supports comments above that classification of these anomalies as immediate repair conditions requiring repair is not warranted by the safety risk presented.

The Associations note that when multiple repair options are available, the final selection is often influenced by logistical considerations. Repair methods are approved and implemented in accordance with industry standards and recommended practices, such as ASME B31.4-2006. However, these standards often lag behind emerging technologies, making it difficult to utilize innovative technologies and processes to gain industry acceptance. For instance, PipeSpring, a steel coil composite wrap that is neither a welded steel sleeve nor fiber-reinforced sleeve, does not align fully with all ASME PCC-2 requirements. Smartpipe or similar composite liner should also be an accepted repair technology in Part 192. This can be installed within the existing pipeline and allow it to return to safe operation. In the case of metal powder cold spray, a fiberglass layer is unnecessarily added just to satisfy the definition of a "composite" repair. These examples highlight the limitations of current standards in accommodating novel and non-traditional repair technologies.

Notwithstanding these limitations, the Associations' members report using the following industry standards: PRCI Pipeline Repair Manual; R-STRENG and other failure pressure calculators; and ASME B31.4-2006.

The Associations' members report the following approximate average cost associated with various repair methods.

- Leak Clamps ($10k);
- Composite Sleeves: ($30k);
- Welded Sleeves: ($50k); and
- Pipe Replacement: ($200k).
- Sanding: Non-destructive Examination (NDE) tech day rate

<u>ANPRM Question III.A.8.</u>
"What proportion of small businesses, small organizations, or small government jurisdictions, as defined in the Regulatory Flexibility Act (5 U.S.C. 6010 et seq.) and its implementing regulations, operate different categories of gas, hazardous liquid, and carbon dioxide pipelines subject to PHMSA anomaly repair criteria, remediation timelines, and IM requirements? Please provide information about the nature and types of activities of small businesses and other small entities operating in midstream gas, hazardous liquid, and carbon dioxide pipeline sectors. How should the agency ensure that any potential changes to the existing regulations would not disproportionately impact small businesses or other small entities in the sector? Are there alternative regulatory approaches the agency should consider that would achieve its regulatory objectives while minimizing any significant economic impact on small businesses or other small entities?"

<u>Comments of the Associations on Question III.A.8.</u>
Operators of gas transmission and gathering pipeline segments along the energy supply chain are comprised of large and small companies. For smaller companies, as defined in the Regulatory Flexibility Act, there should be appropriate, right-sized regulations to accommodate the fact that they may not have many in-house regulatory, engineering, and compliance resources. For instance, one of the associations, GPA Midstream has 7 members of the 50 total members that operate their gathering assets with around 25 total employees or less. In addition, 14 members of the total 50 members operate their gathering assets with around 50 to 100 employees. Smaller companies

often rely on third-party contractors for specialized services. Because smaller companies lack economies of scale, they can incur higher per-mile compliance costs. Lower staffing levels also could make short compliance timeframes challenging. In addition, as staffing is supplemented by contractors, the availability of these resources might be limited if many in the industry are all vying for the expertise, tools, and processes, which could delay compliance and increase costs.

The Associations hope, with any regulatory action, PHMSA allows for appropriate compliance timelines for small operators. In addition, PHMSA should permit smaller companies to make risk-based decisions, allowing for flexibility in remediation timelines. Industry standards could be adopted and provide for performance-based practices that account for the diverse pipeline operating parameters and risk profiles.

ANPRM Question III.A.9.

"Do the annual, incident, and safety related condition reports required by parts 191 and 195 regulations require the submission of remediation-related information with limited or no safety value for particular categories of gas transmission, hazardous liquid, and carbon dioxide pipelines? Is there information required in the reports that is duplicative with the information required to be submitted to other State or Federal regulatory authorities? What costs would be avoided by eliminating or revising any such reporting requirements?"

Comments of the Associations on Question III.A.9.

Yes, the annual, incident, and safety related conditions reports required by Part 191 require the submission of remediation-related information with limited or no safety value. The regulatory requirements for annual reports (§ 191.17), incident reports (§ 191.15), and safety related condition reports (§ 191.23) often require the submission of duplicative information that goes beyond the scope of what is required by statute, particularly with the safety-related condition reports.

As an initial matter, Associations support PHMSA's recently issued direct final rule that would require that annual reports for gas transmission and gas gathering pipelines be submitted by June 15, instead of March 15 of each calendar year.[32]

The Associations believe that the information required in a safety-related condition report is outdated and has been superseded by some regulations. Notably requirements in §§ 192.714(e) and 192.933(e)(1) requiring that an operator reduce operating pressure upon discovery of an immediate repair condition creates a requirement to submit a safety-related condition report.

Section 191.3 defines an incident as release from a pipeline that results in one or more of the following: a death or personal injury requiring in-patient hospitalization, estimated property damage of $149,700 (including loss to the operator, others, or both, but excluding the cost of gas), or an unintentional estimated gas loss of 3 million cubic feet (MMCF) or more. Under §191.5, an operator must provide notice of an incident to the National Response Center within one hour of confirmed discovery. Section 191.15 requires that an operator submit an incident report to PHMSA within 30 days.

The Associations believe that current regulations require that an operator report incidents for many events that do not affect safety. For example, venting more than 3 MMCF of gas through a relief valve should not be considered an incident. In addition, a gas release that causes estimated

[32] Pipeline Safety: Adjust Annual Report Filing Timelines, Direct Final Rule; Request for Comments, 90 Fed. Reg. 28,047 (July 1, 2025).

property damage (including certain repair costs) of $149,700 should not be reportable if it does not affect public safety. Operators should be required to report incidents within 1 hour of confirmed discovery only if there is a threat to public safety or the release will result in significant disruptions to service.

There also is a significant overlap between the data required in annual reports, incident reports, and safety-related condition reports, particularly regarding remediation activities. This duplication not only consumes valuable time but also drives up compliance costs for operators without a corresponding improvement in safety outcomes. Streamlining these reporting requirements by eliminating redundant fields would reduce the administrative burden, free up resources for proactive safety initiatives, and improve overall regulatory efficiency. PHMSA should consider focusing on high-value safety metrics to ensure reporting efforts are both meaningful and cost-effective.

Finally, the Associations believe that PHMSA has expanded its reporting regulations beyond the congressional mandate and underlying statute. Section 60102(h) of the Pipeline Safety Act requires that PHMSA adopt regulations requiring that an operator of a pipeline facility submit a written report on "any (A) condition that is a hazard to life, property, or the environment; and (B) safety-related condition that causes or has caused a significant change or restriction in the operation of a pipeline facility."[33]

Section 191.23 specifies the conditions that constitute safety-related conditions that must be reported to PHMSA, subject to certain exceptions. The conditions described in § 191.23 exceed those described in the statute. It has been the experience of the Associations' members that PHMSA often does not respond to safety-related condition reports, particularly those where public safety was not impacted. While the Associations recognize that PHMSA uses this data to prioritize inspection activities on operators, this information can easily be reported in the annual report without any adverse safety impact.

For example, many of the Associations' members report as safety related conditions immediate repair conditions that cannot be remediated within 5 working days from discovery simply because a 20% restriction is required in § 192.714 or § 192.933. Taking a required pressure reduction does not automatically make the condition a hazard to life, property, or the environment and does not necessarily constitute a restriction in the pipeline facility. An immediate repair condition should be considered a safety-related condition only if a pressure reduction cannot be implemented or is left in place for a significant amount of time and significantly impacts delivery to a customer.

The Associations recommend that PHMSA revise § 191.23 to create an additional exception to the requirement to report a safety-related condition. The exception would provide that an operator is not required to report a safety-related condition if it does not cause a change or restriction in the operation of a pipeline facility. The Associations believe this change would make the safety-related condition reporting requirements more consistent with the original intent of the statute.

Finally, the Associations recommend that PHMSA permit operators to report safety-related conditions that do not impact public safety or result in significant disruptions to service in annual reports instead of a separate safety-related condition report.

[33] 49 U.S.C. § 60102(h)(1).

ANPRM Question III.A.10.

"Should PHMSA amend its regulations governing prioritization of anomaly remediation on gas transmission (§ 192.714) and hazardous liquid and carbon dioxide pipelines (§ 195.401(b)(3)) to align more closely with its statutory mandate at 49 U.S.C. 108(b) and 49 U.S.C. 60102(a)(1) to prioritize public safety and protection against risks to life and property above other important policy objectives within the scope of its regulatory authority?"

Comments of the Associations on Question III.A.10

Yes, PHMSA should amend these regulations to better align with its statutory safety mandate. PHMSA was established under 49 U.S.C. § 108. Section 108(b) states that PHMSA shall "consider the assignment and maintenance of safety as the highest priority, recognizing the clear intent, encouragement, and dedication of Congress to the furtherance of safety as the highest degree of safety in pipeline transportation and hazardous materials transportation."[34] The Pipeline Safety Act further provides that the purpose of that statute is "to provide adequate protection against risks to life and property posed by pipeline transportation and pipeline facilities."[35] Current prescriptive repair criteria, while well-intentioned, do not fully leverage available technological capabilities and engineering expertise to optimize safety outcomes.

PHMSA can best fulfill its statutory mandate to prioritize public safety by pursuing a risk-based framework that promotes technological advancements and innovative improvements in the identification, assessment and remediation of pipeline anomalies. Access to continually improving inspection and assessment technologies equips operators with enhanced capabilities to detect and more accurately characterize potential threats to public safety. To achieve the full safety benefit of these technologies, PHMSA should establish risk-informed repair criteria and alternative response frameworks that enable operators to direct resources toward anomalies that pose the greatest actual risk to life and property based on engineering analysis and comprehensive risk assessment. This targeted resource deployment would strengthen overall pipeline safety while maintaining rigorous standards. A flexible, risk-informed approach would allow operators to focus resources on the highest-risk conditions while maintaining or enhancing safety outcomes.

The Associations offer an example of where a risk-informed framework would enhance safety benefits. Under current regulations, operators must treat metal loss anomalies with predicted failure pressure (PFP) ≤ 1.1 times MAOP as immediate repair condition, regardless of the actual level of risk. However, a probabilistic analysis method, such as a limit state Monte Carlo simulation, could enable operators to identify which anomalies pose the highest actual risk to public safety. for instance, certain metal loss anomalies at longitudinal seams with PFP $\geq 1.39 \times$ MAOP may demonstrate acceptably low risk through advanced analysis and can be safely monitored. This approach would enable more effective deployment of safety resources, reduce the amount of unnecessary repairs, and preserve a high standard for public and environmental safety. Adding probabilistic analysis alternatives to prescriptive safety factors would modernize the regulatory framework, reduce compliance costs, and better align with PHMSA's statutory mandate to prioritize life and property protection.

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[34] 49 U.S.C. § 108(b).

[35] *Id.* § 60102(a)(1).

B. ANPRM Section III.C Repair Criteria and Remediation Timelines for Part 192—Regulated Gas Transmission Pipelines

ANPRM Question III.C.1.

"Are the regulatory requirements at § 192.712(c) governing performance of ECAs for dents and mechanical damage anomalies on gas transmission lines appropriate? Is an ECA an appropriate means of evaluating dents and mechanical damage anomalies on pipelines in some scenarios but not others? Should PHMSA consider amending any elements of the ECA process prescribed at § 192.712(c) to strike a more appropriate balance between safety benefits and costs? Please identify any specific regulatory amendments that merit consideration, as well as the technical, safety, and economic reasons supporting those recommended amendments."

Comments of the Associations on Question III.C.1.

Section 192.714(c) sets forth the repair criteria for onshore transmission pipelines not subject to integrity management. Section 192.714 requires that an operator treat a dent located on the upper 2/3 of the pipe that is associated with metal loss, cracking, or a stress riser as an immediate repair condition, unless an engineering critical analysis performed in accordance with § 192.712(c) demonstrates that critical strain levels are not exceeded.

If an operator elects to perform an ECA to determine critical strain levels associated with a dent or other mechanical damage, § 192.712(c) requires that the operator develop a procedure and perform the ECA in accordance with specified elements. Section 192.712(c)(11) requires that an operator using an ECA provide PHMSA an advance notification and submit the ECA procedure in accordance with notification procedures set forth in § 192.18.

The Associations offer the following comments regarding the appropriateness of the ECA requirements set forth in § 192.712(c) for addressing dents and other mechanical damage.

1. PHMSA should adopt new §192.712(c) criteria for ECA procedures or, alternatively, eliminate the § 192.18 advance notification requirement for ECA procedures.

Section 192.712(c) sets forth the requirements applicable to an ECA procedure. Given these explicit requirements, an operator should reasonably expect that it will be able to implement its ECA procedure 91 days after providing PHMSA advance notification. In practice, however, the § 192.18 notification process has become a lengthy, cumbersome process bogged down by PHMSA's numerous requests for additional studies and information to support an ECA procedure that was already developed as directed by the regulations. A typical § 192.18 notification process takes over a year to complete and has become an impediment to an operator's ability to use its ECA procedure to perform a critical strain analysis on a dent. This also delays the operator's ability to proceed with the pipeline repair. This outcome does not advance pipeline safety.

Since 2022, those operators that have been able to implement ECAs have gained valuable experience about how the ECA process for dents should be improved to enhance its efficiency without compromising safety. The Associations also have had the benefit of the guidance available in the American Petroleum Institute (API) Recommended Practice 1183, Measuring and Assessing Dents in Pipelines.

API RP 1183 contains detailed technical discussions on dent formation, strain and fatigue and failure modes and mechanisms. Operators rely on guidance contained in API RP 1183 to make informed decisions regarding the management of dents on their systems.

Capitalizing on operators' ECA experiences and based on the guidance contained in API RP 1183, the Associations have collaborated with API to develop a new proposed ECA process for dents. The Associations recommend that PHMSA replace existing § 192.712(c) with this amended ECA process.

Proposed new § 192.712(c).

§ 192.712 Analysis of predicted failure pressure and critical strain level

(c) **Dents and other mechanical damage.** To evaluate dents and other mechanical damage that could result in a stress riser or other integrity impact, an operator must develop a procedure and perform an engineering critical assessment as follows:

1. The size, location, and when appropriate, the shape of the dent.
2. Consideration for any interacting features. Examples include features such as mechanical damage, metal loss, proximity to welds (both seam and girth), or other stress concentrators, and past dent failure(s) history.
3. Review high-resolution metal loss, high-resolution deformation, inertial mapping, and crack detection inline inspection data for damage in the dent area and any associated weld region, including available data from other-inline inspections.
4. Consideration of potential threats in the vicinity of the condition such as ground movement.
5. A strain assessment for the dent that includes:
    a. Characterization of strain for the dent using either geometry curvature-based strain, or Finite Element Analysis.
    b. Evaluate the strain level associated with the dent and any interacting threats.
6. A fatigue assessment for the anomaly or dent or initial crack(s) in the dent that includes:
    a. A valid fatigue life prediction model such as an analytical model, empirical or Finite Element Analysis that is appropriate for the pipeline segment.
    b. The models and subsequent evaluation of fatigue life should appropriately account for interacting threats or features.
7. Account for uncertainties in material properties, model inaccuracies and inline inspection measurement through the use of an appropriate safety factor.
8. Detailed records of the methods used, the results, and assumptions made.

It is the Associations' understanding that API is developing a second edition of RP 1183 that will address an ECA process for dents and mechanical damage. If PHMSA does not amend § 192.712(c) as described above, the Associations expect to recommend that PHMSA incorporate the applicable sections of the revised version of API RP 1183 into Part 192.

Alternatively, if PHMSA does not entirely revise § 192.712(c), the Associations recommend that PHMSA amend § 192.712(c)(11) to eliminate the requirement to provide advance notification of an operator's intent to use an ECA procedure since PHMSA lists the requirements of the ECA in § 192.712(c)(1-10). An operator that develops an ECA procedure in accordance with § 192.712(c) should be allowed to implement it without any advance review. As with any other procedure, an operator's ECA procedure would be subject to audit by PHMSA and potential enforcement if the procedure does not comply with the regulations. The advance notification requirement under § 192.712(c)(11) should be limited to an operator's intention to use "other technologies."

Eliminating the advance notification requirement would promote safety by facilitating the deployment of improved assessment tools to address dents and would achieve a better balance of compliance costs and safety benefits.

2. PHMSA should clarify § 192.714's requirements when an operator discovers a dent or other mechanical damage during a field excavation.

Section 192.714 sets forth repair criteria for onshore transmission pipelines located outside of HCAs. Section 192.714(b) requires that an operator perform repairs in a safe manner and further requires that a pipeline segment's operating pressure during repairs be less than the predicted failure pressure determined in accordance with § 192.712. Section 192.714(c) further requires that an operator remediate conditions in accordance with a specified schedule and requires that, unless § 192.714(d) "provides a special requirement for remediating certain conditions, an operator must calculate the predicted failure pressure of anomalies or defects."[36] Section 192.714(c)(2) then provides that each condition meeting any of the repair criteria of § 192.714(d) must be "[r]epaired by a method, shown by technically proven engineering tests and analyses, that will permanently restore the pipeline's MAOP based upon the determined predicted failure pressure times the design factor for the class location in which it is located."[37]

The Associations note that a dent with metal loss or other mechanical damage can be discovered either through an ILI or in the field during an excavation. The Associations' members report ambiguity regarding how the requirements of § 192.714 apply, particularly with respect to the need for an ECA, when dents are discovered in the field. The Associations request that PHMSA clarify that dents found through field excavation can be evaluated as stated in B31.8-2018, section 851.4.1, which allows plain dents to remain in service if the dent does not exceed 6% nominal pipeline diameter and if corrosion is present, the calculated failure pressure from metal loss is less than the MAOP of the pipeline or the dent does not exceed 2% nominal pipeline diameter at a ductile girth or long seam weld. Dents that do not meet these criteria would be evaluated through the proposed § 192.712(c) ECA process to determine if a repair is necessary. Section 192.714 also should allow an operator to proactively implement a dent repair and bypass the dent evaluation process if the pipeline needs to be returned to service in a more timely manner.

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[36] 49 C.F.R. § 192.714(c).

[37] 49 C.F.R. § 192.714(c)(2).

ANPRM Question III.C.2.

"Should ECA methodologies or elements thereof within consensus industry standards and recommended practices (e.g., API RP 1183)[38] inform the ECA requirements in § 192.712? Are the safety factors, required elements, and supporting records identified in consensus industry standards and recommended practices appropriate to use in evaluating dent and mechanical damage anomalies on gas transmission lines, or are alternative approaches advisable? Please identify any specific regulatory amendments that merit consideration, as well as the technical, safety, and economic reasons supporting those recommended amendments."

Comments of the Associations on Question III.C.2.

As noted above, the Associations recommend a complete revision of § 192.712(c) to reflect operator experience, lessons learned, and principles contained in those sections of API RP 1183 applicable to ECAs.

If § 192.712(c) is not replaced with the principles proposed above, the Associations recommend that PHMSA consider incorporating by reference the ECA applicable sections of the second edition of API RP 1183, which is expected to be released in the near future. The guidance contained in API RP 1183 reflects current engineering best practices and provides a technically sound foundation for evaluating dent and mechanical damage anomalies.

ANPRM Question III.C.3.

"What were the incremental, per unit costs and benefits associated with establishing an ECA program and subsequently conducting each ECA? Were there any cost savings associated with deferred remediation due to the ECA?"

Comments of the Associations on Question III.C.3.

The Associations are in the process of compiling specific cost data and will submit it at a later date. Preliminary feedback from the Associations' members indicate that performing an ECA can result in savings of $50,000 to $250,000 per excavation, particularly when an ECA enables an operator to avoid having to excavate in environmentally sensitive or difficult to access areas. One operator reported that a single dent ECA can cost between $10,000 and $20,000, representing significant cost savings over having to perform an excavation.

Importantly, benefits associated with performing an ECA instead of performing an excavation include avoiding environmental and land disturbance, avoiding customer service disruptions, averting product loss, and reducing reduced risk to personnel safety.

[38] API, Recommended Practice 1183, "Assessment and Management of Pipeline Dents" (First edition 2020).

ANPRM Question III.C.4.

"Are part 192 repair criteria, remediation timelines, and IM requirements for gas transmission pipelines appropriate for dents with metal loss or other interacting integrity threats? What technologies or methods could be used to evaluate dent anomalies with metal loss and other interacting threats? Are there any pertinent consensus industry standards or recommended practices that should be incorporated by reference in PHMSA regulations? Please identify any specific regulatory amendments that merit consideration, as well as the technical, safety, and economic reasons supporting those recommended amendments."

Comments of the Associations on Question III.C.4.

As discussed elsewhere in these comments, the Associations do not believe that Part 192 repair criteria and timelines for remediating dents with metal loss or interacting threats adequately reflect advancements in ILI technology or allow an operator to differentiate between meaningful threats and benign features. The repair criteria should be updated to reflect modern detection capabilities, validated assessment methods, and consensus standards.

Modern ILI technologies, particularly high-resolution Magnetic Flux Leakage (MFL). EMAT and strain-based tools, have significantly increased detection sensitivity. These tools enable an operator to identify very minor wall thickness variations and geometric deformations that previously were undetectable and that often fall within pipe manufacturing tolerances (e.g., API 5L). As a result, many features classified as "dent with metal loss" under current regulations are actually non-injurious, manufacturing-related conditions that pose no active threat to pipeline integrity. Despite this, PHMSA regulations reflect a one-size-fits-all approach requiring that many dents with indication of metal loss be repaired, regardless of the level of the safety risk. This overly conservative approach does not consider critical contextual factors.

Overly prescriptive inflexible requirements do not appropriately balance safety benefits and compliance costs and are inconsistent with integrity management risk-based principles. PHMSA should amend regulations that discourage or delay the use of advanced technologies and limit the ability of operators to deploy accepted engineering analyses designed to achieve better safety outcomes more efficiently.

ANPRM Question III.C.5.

"Are the re-assessment frequencies for anomalies on gas transmission pipelines (§ 192.712(h)) that have been evaluated using an ECA appropriate? Should PHMSA consider amending those re-assessment intervals to strike a more appropriate balance between safety benefits and costs?"

Comments of the Associations on Question III.C.5.

Section 192.712(h) provides that if an operator uses an ECA to determine maximum reevaluation intervals, the operator must reassess the anomaly within 7 calendar years if the anomaly is in an HCA, and within 10 years if the anomaly is located outside of an HCA.

The Associations do not believe that these re-assessment intervals are appropriate and recommends that PHMSA amend them to achieve a better balance between compliance costs and safety benefits. The Associations offer the following comments:

1. *An operator should not be required to repeat an ECA on the same anomaly during each subsequent reassessment if no significant geometric or operational change is detected.*

If an ECA has demonstrated that an anomaly has a remaining life significantly longer than the required reassessment interval, repeating the full ECA adds unnecessary costs without a corresponding safety benefit. Requiring a new ECA each reassessment cycle undermines the purpose of using validated engineering methods to predict anomaly behavior over time.

Instead, the Associations recommend that operators be permitted to rely on the original ECA unless subsequent in-line inspection data indicates growth or a change in anomaly characteristics. Such an approach is consistent with risk-based principles. For each ILI assessment, the Associations recommend that an operator be permitted to confirm the validity of dent ECAs previously performed, instead of having to perform an entirely new ECA.

2. *An operator should be able to demonstrate that longer re-assessment intervals will not compromise safety.*

The Associations recommend that PHMSA consider permitting an operator to establish re-assessment intervals that are longer than those specified in § 192.712(h) if the operator can demonstrate through validated ECA methodologies and robust integrity data, that longer intervals would not compromise safety. Providing operators such flexibility would encourage innovation and efficient resource allocation while remaining accountable for strong safety oversight. The Associations also recommend that, to enhance consistency and regulatory confidence in reassessment decisions, PHMSA should provide more clear guidance regarding acceptable ECA practices and data quality expectations.

3. *PHMSA should clarify that an operator has up to ten years to perform an assessment on a newly activated threat identified in a covered segment.*

As described above, in its response to Question III.A.5, the Associations disagree with this PHMSA's Interpretation Letter PL-21-004[39] which stated that an operator must assess a newly activated threat within the same assessment cycle as previously identified threats within the covered pipeline segment, regardless of when the threat became activated. and request that PHMSA withdraw it. The Associations request that PHMSA withdraw this letter of interpretation because §§ 192.919 and 192.921 provide a more appropriate timeline for completing a baseline assessment for a newly activated threat.

The following example illustrates the challenges associated with PHMSA's Letter of Interpretation. An operator determines that a covered pipeline segment is susceptible to hard spots after the operator incorporates the results of a recently released study into its integrity management

[39] Letter of Interpretation, PI-21-0004 (June 23, 2021).

plan. Section 192.919(a) requires that the operator update its baseline assessment plan and § 192.919(b) requires that the operator select a methodology to perform a baseline assessment. After considering all risk factors to each covered segment in the pipeline system, the operator determines an appropriate schedule for performing a baseline hard spot assessment in accordance with § 192.919(c).

Subpart O does not directly address the maximum interval required for completing the baseline assessment of the newly activated threat in an existing HCA. However, guidance may be gleaned under other regulations. Specifically, § 192.921(f) an operator is provided up to ten years from the date an HCA is identified to complete a baseline assessment for a newly identified HCA. Section 192.921(g) allows an operator ten years to complete a baseline assessment for a newly installed segment of pipeline.

The Associations believe that a newly activated threat on a covered pipeline segment is analogous to a newly identified HCA and newly installed pipeline segment. Identifying a newly activated threat in an existing HCA presents a comparable risk profile to a newly identified (unassessed) threat that may be discovered on a comparable pipeline (similar environment, construction, vintage, etc.) in a newly discovered HCA. The Associations believe that an operator should be permitted for up to 10 years to assess that newly activated threat.

The Associations request that PHMSA withdraw its Letter of Interpretation Letter, PL-21-0004. In addition, to provide regulatory clarity, the Associations request that PHMSA amend § 192.921(f) to allow an operator 10 years to complete a threat-specific baseline assessment for a new threat.

III. CONCLUSION

The Associations appreciate the opportunity provided by PHMSA's advance notice of proposed rulemaking to provide thoughts and recommendations regarding Part 192 repair criteria, remediation guidelines and integrity management requirements.

Respectfully submitted,

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