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

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

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

FILED BY

AMERICAN PETROLEUM INSTITUTE
LIQUID ENERGY PIPELINE ASSOCIATION
GPA MIDSTREAM ASSOCIATION
AMERICAN FUEL & PETROCHEMICAL MANUFACTURERS

July 21, 2025

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I. Introduction

The American Petroleum Institute (API),[1] the Liquid Energy Pipeline Association (LEPA),[2] the GPA Midstream Association (GPA),[3] and the American Fuel & Petrochemical Manufacturers (AFPM)[4] (collectively, the "Associations") respectfully submit the following comments in response to the Pipeline and Hazardous Materials Safety Administration's (PHMSA) "Repair Criteria for Hazardous Liquid and Gas Transmission Pipelines" Advanced Notice of Proposed Rulemaking (ANPRM).[5] The Associations welcome the opportunity to comment in this proceeding and commend PHMSA for recognizing the need to modernize the pipeline safety regulations.

The Associations' member companies are committed to protecting the health and safety of their workers, neighbors, customers, and the communities through which crude oil, refined petroleum, and other products are shipped. Our members share PHMSA's commitment to pipeline integrity, safety, and reliability, and are steadfast in that commitment.

In the ANPRM, PHMSA has requested stakeholder input on potential opportunities to improve its repair and integrity management requirements for gas transmission (49 C.F.R Part 192) and hazardous liquid and carbon dioxide (49 C.F.R Part 195) pipelines. PHMSA also seeks input on

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[1] API represents all segments of America's natural gas and oil industry, which supports more than 11 million U.S. jobs and is backed by a growing grassroots movement of millions of Americans. Our approximately 600 members produce, process and distribute the majority of the nation's energy, and participate in API Energy Excellence®, which is accelerating environmental and safety progress by fostering new technologies and transparent reporting. API was formed in 1919 as a standards-setting organization and has developed more than 800 standards to enhance operational and environmental safety, efficiency and sustainability.

[2] LEPA promotes responsible policies, safety excellence, and public support for liquids pipelines. LEPA represents pipelines transporting 97 percent of all hazardous liquids barrel miles reported to the Federal Energy Regulatory Commission. LEPA's diverse membership includes large and small pipelines carrying crude oil, refined petroleum products, NGLs, and other liquids.

[3] GPA Midstream is composed of over 50 corporate members that directly employ over 57,000 employees that are engaged in the gathering, transportation, processing, treating, storage and marketing of natural gas, natural gas liquids (NGLs), crude oil, and refined products, commonly referred to in the industry as "midstream activities." In 2023, GPA Midstream members operated over 500,000 miles of pipelines, gathered over 91 Bcf/d of natural gas, and produced over 5.3 million barrels/day of NGLs from over 365 natural gas processing facilities.

[4] AFPM is a national trade association representing most U.S. refining and petrochemical manufacturing capacity. AFPM's member companies produce the gasoline, diesel, and jet fuel that drive the modern economy, as well as the petrochemical building blocks that are used to make the millions of products that make modern life possible–from clothing to life-saving medical equipment and smartphones. As such, AFPM members strengthen economic and national security while supporting more than 3 million jobs nationwide. To produce these essential goods, AFPM members depend on all modes of transportation to move their products to and from refineries and petrochemical facilities and have made significant infrastructure investments to support and improve the safety and efficiency of the transportation system. AFPM member companies depend upon an uninterrupted, affordable supply of crude oil and natural gas as feedstocks for the transportation fuels and petrochemicals they manufacture. Pipelines are the primary mode for transporting crude oil and natural gas to refiners and petrochemical facilities and refined products from those same facilities to distribution terminals serving consumer markets.

[5] Pipeline Safety: Repair Criteria for Hazardous Liquid and Gas Transmission Pipelines, 90 Fed. Reg. 21,715 (proposed May 21, 2025).

whether to allow a risk-based approach for determining inspection intervals for in-service breakout tanks under Part 195. While the focus of the ANPRM is anomaly repair criteria and risk-based inspection of breakout tanks, PHMSA also poses questions on the use of innovative technologies, discovery of conditions, evaluation of anomalies on pipe outside of the IM program, pipeline repair practices, and reporting requirements.

The Associations provide comments on the hazardous liquids aspects of the ANPRM. The Associations have worked with other industry stakeholders to align, as much as possible, the approach to gas and liquids repair criteria. This comment letter includes an executive summary that lays out the theme of the Associations' comments, relevant background, and the need for regulatory change. Next, the Associations summarize their top priorities in this rulemaking. Finally, the Associations go through each relevant section of the ANPRM and provide specific comments, proposed regulatory text, technical support and cost-benefit information. Several of the ANPRM questions request information on the same subject matter, either as part of a general request or addressing specific issues. As a result, the Associations repeat certain content in multiple locations throughout these comments as appropriate to the question. The Associations will file supplemental information regarding economic impacts as they continue to collect cost-benefit data relevant to the ANPRM.

II. Executive Summary

PHMSA's integrity management (IM) regulations are outdated. PHMSA finalized the first IM regulations 25 years ago[6] based on the limited technology and engineering capabilities available at the time. PHMSA's ANPRM presents an opportunity to modernize safety regulations related to pipeline inspection and defect analysis, scheduling and repairs, and tank inspections. Today's Part 195 integrity management (IM) regulations require liquid pipeline operators to schedule excavation and repair of certain defects that operators know are not harmful. Similarly, Sec. 195.432 requires operators to take breakout tanks out of service for inspections based on prescriptive intervals, which result in costly inspections well before they are needed.

The Associations propose regulatory changes that would allow operators to more closely align their integrity resources to actual risk. Operators know these changes are safe and appropriate because they have modern tools, extensive data and studies, and 25 years of IM implementation experience that show this. By leveraging advanced technology and engineering practices, operators know more than ever about the conditions of their pipelines. The regulations should reflect that knowledge.

[6] Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators with 500 or More Miles of Pipeline), 65 Fed. Reg. 75,378 (Dec. 1, 2000).

III. Background

The IM program applies enhanced safety measures to pipelines located in High Consequence Areas (HCA) where a release could impact people or sensitive environments.[7]

While PHMSA envisioned that the IM rule would provide operators with the flexibility to develop programs that "evolve and take advantage of changing technologies,"[8] the fact is that the IM rules do not allow this flexibility when it comes to the evaluation and scheduling of defects for repair. While PHMSA has periodically amended the IM rules, changes to the provisions on repair and defect evaluation have been minimal and have not matched technology improvements and operator experience.[9]

In addition to IM, a second core focus of the Associations' comments relates to the use of risk-based inspection intervals (RBI) for breakout tanks. Sec. 195.432 imposes prescriptive requirements for in-service breakout tank inspections, which prohibit the use of sound engineering practices to establish inspection frequencies. PHMSA's current approach restricts the use of tank safeguards and leak prevention barriers and has not kept pace with innovations in the most recent editions of consensus industry standards, preventing operators from using advancements in tank risk management.

a. Examples of Inefficiency

Unnecessary inspections, excavations, and repairs drive hundreds of millions of dollars in annual costs without corresponding safety benefits. Examples of how current repair criteria and tank inspection requirements drive the inefficient application of resources are provided below and detailed further in these comments.

- **Longitudinal Seam Weld Corrosion**: The current repair criterion for long seam weld corrosion,[10] and PHMSA's interpretation of this requirement, has resulted in thousands of unnecessary excavations to address non-injurious corrosion anomalies. For example, two operators reported to the Associations that they conducted a combined 2,700 digs to

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[7] 49 C.F.R. §§ 195.6, 195.450, 195.452. PHMSA also has pipeline assessment and repair requirements for non-HCA pipe, which are significantly more flexible than the IM requirements. *See* 49 C.F.R. § 195.416.

[8] 65 Fed. Reg. 75,378, 75,382 (Dec.1, 2000).

[9] Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Repair Criteria), 67 Fed. Reg. 1,650 (Jan. 14, 2002) (The original IM final rule included substantial modifications to the repair criteria which had not been addressed in the NPRM. PHMSA solicited comment to those changes and addressed them in 2002 rulemaking); Pipeline Safety: Integrity Management Program Modifications and Clarifications, 72 Fed. Reg. 39,012 (Jul. 17, 2007) (requiring operators to provide notice to PHMSA for temporary and long-term pressure reductions, and allowing the use of an alternative method to calculate reduced operating pressures); Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations, 80 Fed. Reg. 12,762 (Mar. 11, 2015) (again addressing the alternative method to calculate reduced operating pressures); Pipeline Safety: Safety of Hazardous Liquid Pipelines, 84 Fed. Reg. 52,260 (Oct. 1, 2019) (amending requirements related to information analyses, non-IM assessment and other topics).

[10] 49 C.F.R. § 195.452(h)(4)(iii)(H).

investigate 6,000 indications of corrosion of or along the long seam weld. These operators found only incidental corrosion features that did not preferentially affect the long seam weld or pose a threat to pipeline integrity. These efforts cost approximately **$135 million** with little benefit to pipeline safety. The Associations propose alternative criteria for long seam weld corrosion that is focused on actual safety risk and aligns with recent PHMSA changes to the repair criteria for gas pipelines.

- **Dents:** The current depth-based repair criteria for dents do not reflect the latest engineering practices for dent assessments and have resulted in a significant number of unnecessary excavations and repairs. The Associations propose to keep the depth-based criteria for dents, and to also allow operators the option to apply modern Engineering Critical Assessment (ECA) methods to determine if dents are a threat to pipeline integrity. One operator informed the Associations it would save **$1+ million annually** if it were permitted to use the Association's proposed dent criteria.

- **Breakout Tanks**: Current tank inspection requirements[11] include prescriptive maximum inspection intervals and disallow modern RBI approaches to tank inspection. As a result, operators routinely are required to remove tanks from service and undertake costly inspections well before the risk data indicates is necessary. Based on member data regarding the frequency and cost of tank inspections, the Associations estimate that simply allowing the modern RBI approach for breakout tanks that is already provided in existing industry standards would result in **$220 million in annual** savings that could be reallocated to other higher risk maintenance activities.

PHMSA has never fully evaluated the costs of the IM repair criteria or prohibiting the use of RBI as required by the Pipeline Safety Act.[12] The agency's Final Regulatory Evaluation published to support the original IM rule did not consider the cost of the repair criteria, finding that "OPS has no information on which to base assumptions regarding the number of anomalies that will require action or the cost of that action. Costs associated with remediation are therefore not estimated as part of this analysis."[13] In later regulatory impact analyses evaluating proposed or final amendments to the IM requirements, PHMSA continued to omit repair cost data.[14] In a 2002 Final Regulatory Analysis, the agency asserted no cost data was needed because Sec. 195.401 already

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[11] 49 C.F.R. § 195.432. The current regulations incorporate API Standard 653 for tank inspections but prohibit the use of well-established RBI procedures in that standard to set inspection intervals.

[12] 49 U.S.C. § 60102(b)(3).

[13] Research and Special Programs Administration, Final Regulatory Evaluation: Pipeline Integrity Management in High Consequence Areas at 21, Docket No. PHMSA-RSPA-1999-6355, Regulations.gov, https://www.regulations.gov/document/PHMSA-RSPA-1999-6355-0069 (Nov 6, 2000).

[14] Research and Special Programs Administration, Final Regulatory Evaluation: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Pipeline Operators with less than 500 miles of Pipelines at 31, Docket No. PHMSA-RSPA-2000-7408, Regulations.gov, https://www.regulations.gov/document/PHMSA-RSPA-2000-7408-0033 (Apr. 18, 2002); Preliminary Regulatory Impact Analysis, Pipeline Safety: Safety of Hazardous Liquid Pipelines Notice of Proposed Rulemaking (NPRM) at 3, Docket No. PHMSA-2010-0229, Regulations.gov, https://www.regulations.gov/document/PHMSA-2010-0229-0037 (Oct. 15, 2015)

required repairs, so that the IM repair criteria did not establish a new requirement for operators.[15] Similarly, PHMSA did not conduct a cost-benefit analysis for removing the ability to use RBI. The change came as part of an IBR rulemaking, and instead of performing an assessment of the RBI revisions, the agency made a general statement it "estimates the costs of incorporating these standards to be negligible and the net benefits to be high."[16] Today's rulemaking provides PHMSA with the opportunity analyze the actual costs, benefits, and alternative regulatory options, and consider operators' experience under the IM and tank inspection rules.

b. *Technology Improvements*

Pipeline operators work diligently to construct, operate, and maintain their facilities safely, reliably, and with a goal of zero incidents. Operators improve their pipeline safety programs based on learnings from pipeline assessments, accidents, and operations. Operators apply these lessons as part of the industry's commitment to continuous improvement, sharing and learning, and often utilizing pipeline safety management systems.[17] These efforts recognize that under every pipeline company's "license to operate" each operator is ultimately responsible for the prioritization of evaluations and repairs and identifying and taking corrective action for any injurious anomaly.

Operators do this best by leveraging technology. Indeed, advancing technology and driving innovation are core values of the liquids pipeline operating community. Many of the Associations' member companies invest substantial funding and personnel resources into technology development, participate in industry collaborative research, and support PHMSA's research programs. Through these efforts, substantial improvements have been made in the tools and techniques for pipeline integrity management and breakout tank inspections. Modern inspection tools harness magnetic and ultrasound imaging and provide extensive information and data on pipe condition. Advanced engineering assessment capabilities, including ECA and failure pressure calculations among others, are then used to characterize the risks associated with specific defects. Together these tools provide the opportunity for more flexible safety programs tailored to the characteristics and operating conditions of specific pipelines and breakout tanks. With better pipeline data and tools, operators can make more informed decisions about what needs to be repaired and when.

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[15] Research and Special Programs Administration, Final Regulatory Evaluation: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Pipeline Operators with less than 500 miles of Pipelines at 31, Docket No. PHMSA-RSPA-2000-7408, Regulations.gov, https://www.regulations.gov/document/PHMSA-RSPA-2000-7408-0033 (Apr. 18, 2002) ("No repair costs were included in the Regulatory Evaluation. This rule does impose time limits on the repair of certain types of defects. Generally, however, repair of conditions that could adversely affect safe operation of a pipeline is already covered by 49 CFR § 195.401. Repair is thus not a new requirement in this rule.").

[16] 80 Fed. Reg. 176 (Jan. 5, 2015).

[17] *See* Am. Nat'l Standards Inst. & Am. Petroleum Inst., Recommended Practice 1173 Pipeline Safety Management Systems, (1st ed. 2015).

When the IM rule was first promulgated in 2000, the tools available for detecting and analyzing defects were less advanced compared with today's technology.[18] PHMSA developed the IM rule in the context of the tools and techniques available at the time. As a result, repair criteria were highly conservative, reflecting the uncertainties and unknowns associated with early tools and methods of analysis. The tools and techniques available to pipeline operators today far exceed those that were available 25 years ago, and the regulations need to be updated to reflect the current state of the art for pipeline integrity.

Regarding ILI tools, the resolution, sizing accuracy, defect differentiation capability, and analysis reliability of this technology has progressively improved. For example, the high-resolution magnetic flux leakage (MFL) ILI tools that were available in 2000, considered best in class at the time, had hundreds of sensors and claimed metal loss depth measurement accuracy of +/-10% of the wall thickness at a probability of detection (POD) of 80%. These tools could differentiate pitting, general metal loss and gouging. Today's ultrasonic and high resolution MFL technologies have thousands of sensors and accuracies that have improved to +/- 0.03" at a POD of 90%. Modern tools can differentiate between general metal loss, gouging/mechanical damage, pitting, grooving (axial and circumferential), slotting (axial and circumferential) and pinhole corrosion.

The improvements discussed above are reflected in many industry consensus standards and have contributed to improvements in safety performance. PHMSA incorporates at least 60 technical standards into the pipeline safety regulations. Modern editions of industry consensus standards reflect decades of industry experience, integrate new technologies and analytical methods, and provide the latest proven engineering assessment methods that are used to identify conditions that require further action. Development of these consensus standards helps to keep industry up to date with new technologies and best practices, and incorporation of these standards into the regulations helps improve safety.

Unfortunately, the current IM regulations do not allow pipeline operators to take full advantage of these many improvements.

c. *Need for Change*

Today, outdated IM analysis and repair criteria in Part 195 limit how operators are allowed to evaluate defects and require operators to repair defects that they know are not harmful. These antiquated regulatory criteria needlessly divert operator resources toward excavating and repairing defects that do not need to be repaired. Unnecessary excavations, in turn, increase the risk of human error that puts operator personnel and the public at risk. Similarly, the prohibition on the use of RBI for tanks precludes operators from using risk-based analysis to establish inspection intervals. The current prescriptive requirements, drive costly and unnecessary inspections, which include taking tanks out of service and exposing personnel to risk.

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[18] *See e.g.,* U.S. Gov't Accountability Off., GAO-RCED-92-237, Report to Congressional Committees, Natural Gas Pipelines, Greater Use of Instrumented Inspection Technology Can Improve Pipeline Safety (1992), https://www.gao.gov/assets/rced-92-237.pdf.

PHMSA should allow operators to use modern engineering practices to assess conditions on their pipeline systems and apply their resources toward maintenance activities that are truly needed to reduce risk and improve public safety. The Associations believe that pipeline safety will meaningfully improve if operators are allowed to use modern tools and techniques that the industry has developed over the past 25 years in ways that they cannot under today's prescriptive and outdated regulations. The Associations' comments are intended to advance this goal. In the proposals below the Associations propose areas where more flexibility and modern tools are needed and also areas where experience tells us that more prescriptive criteria are appropriate. For example, the Associations propose two new immediate repair criteria for cracks to reflect advances in ILI tools for crack detection. This call for prescriptive requirements where they are needed and flexibility where appropriate demonstrates industry's commitment to safety

d. Consistency with Executive Orders

PHMSA's ANPRM seeks to ensure resources are directed to the highest priority threats, using modern technology and engineering practices. PHMSA's ANPRM is also intended to align the agency's regulatory programs with the national energy goals and policies set out in recent Executive Orders. In implementing these objectives, PHMSA can alleviate unnecessary regulatory burdens, consistent with Executive Order 14,192,[19] while promoting the production and supply of American energy consistent with Executive Orders 14,154 and 14,156.[20]

In these comments, the Associations propose revising the text of certain Part 195 regulations. Where the Associations propose to add regulatory text in certain areas, these proposed changes, if adopted, are de-regulatory in nature and would be compliant with the Executive Order 14,192. These changes would reduce regulatory burdens, allow for the use of new technology, and restore the risk-based purpose of the IM program and other Part 195 regulations. The Associations' proposed changes are also intended to improve pipeline safety outcomes through the better and smarter allocation of operator resources.

IV. Priority Amendments

The Associations wish to highlight certain key priorities that PHMSA should include in any update to 49 CFR Part 195:

Modernizing Repair Criteria

Modern technologies and analytical methods provide the opportunity for more flexible IM repair criteria and scheduling, tailored to specific pipelines and operating conditions. The current one-size-fits-all, prescriptive requirements are inefficient and drive significant, unnecessary costs. Instead, PHMSA regulations should allow operators to utilize risk-based decision-making to establish inspection frequency and repair schedules. The changes the Associations propose follow

[19] Exec. Order No. 14,192, Unleashing Prosperity through Deregulation, 90 Fed. Reg. 9,065 (Feb. 6, 2025).

[20] Exec. Order No. 14,154, Unleashing American Energy, 90 Fed. Reg. 9,065 (Feb. 6, 2025); Exec. Order No. 14,156, Declaring a National Energy Emergency, 90 Fed. Reg. 8,433 (Jan. 29, 2025).

a common theme – maintaining pipeline safety by restoring a risk-based approach to the IM program.

Priority changes include:

- **Restoring the Risk-Based Approach through Failure Pressure-Based Decision-Making**: The Associations request PHMSA allow operators to base pipeline evaluation and repair schedules on an analysis of calculated failure pressures and the remaining strength of the pipeline at the location of corrosion, other metal loss, and crack features. In tandem with this change, the Associations request that PHMSA update the regulations to recognize the many improvements in failure pressure calculation methodologies and allow operators to use the method best suited to each anomaly. This change would modernize the current, one-size-fits-all repair criteria for these kinds of defects and reduce the number of non-injurious defects that operators must repair.

- **Crack-Like Features – Differentiating What Needs to be Repaired Quickly and What Can be Monitored**: The Associations request PHMSA expand the list of immediate repair conditions to include certain crack-like features that are not currently listed, aligning industry advancements and integrity management best practices and demonstrating industry's commitment to safety. Operators have also learned that not all crack-like features are the same. In recent years, operators have deployed advanced ultrasonic crack detection tools to find cracks in the pipe body and longitudinal seam, created calculation methods for cracks, and learned which crack-like features warrant immediate repair. At the same time, experience has shown other types of crack-like features are non-injurious. Operators can safely monitor these features or schedule these features for evaluation and repair, as appropriate based on risk. These changes would recognize the role of advanced technology and operator experience and prioritize repairs accordingly.

- **Modernizing Corrosion Repair Criteria to Reduce Unnecessary Repairs and Better Allocate Resources**: The Associations request PHMSA update certain corrosion repair criteria to reflect learnings from modern assessment tools and operational experience. Specifically, the current repair condition requiring remediation of all corrosion of or along a longitudinal seam weld does not reflect risk or fitness for service engineering calculations and drives substantial unnecessary repairs. This repair criterion makes no differentiation between the types of corrosion (for example selective seam versus general corrosion) and does not account for differences in risk based on pipe materials or long seam characteristics. In recent changes to the repair criteria for gas transmission pipelines, PHMSA recognized this problem and changed the seam-related corrosion repair criteria to focus on preferential seam corrosion.

  The proposed changes related to failure pressure calculation would also modify other corrosion-related repair criteria to make them more focused on risk. Together, these changes would substantially reduce the number of unnecessary and wasteful repairs required under the IM regulations.

- **Modernizing Dent Repair Criteria to Reduce Unnecessary Repairs and Better Allocate Resources**: The Associations request PHMSA allow operators the option to use fatigue life and strain calculations to determine repair timelines for dents. PHMSA should allow operators to use modern tools like Engineering Critical Assessment (ECA) to schedule dent repairs, as the Part 192 regulations allow for gas transmission pipelines. The current Part 195 dent repair criteria are highly prescriptive and do not allow operators to use modern-day evaluations to determine if a dent is injurious. As with corrosion, modernization of dent criteria would also reduce the number of unnecessary and wasteful repairs.

- **Updating Repair Scheduling Categories**: The Associations request PHMSA create a new 1-year repair condition that combines and updates the current 60-day and 180-day repair conditions. This change would recognize that advanced assessment tools and operator experience with anomaly investigation and repair have shown many types of defects can be safely scheduled for repair on a 1-year basis. A 1-year repair deadline for these defects also allows operators more time to plan for such repairs, obtain permits and arrange and optimize necessary resources.

<u>In-Service Breakout Tank Inspections</u>

- **Risk-Based Inspection Intervals:** The Associations request PHMSA update the regulations for inspections of breakout tanks to allow operators to use modern technology and analytical approaches to maintain tank integrity. While PHMSA has incorporated the API 653 industry standard for tank inspections, it has disallowed operators from using risk-based alternative methods in that standard to set tank inspection intervals. The Associations request that PHMSA remove this limitation and incorporate the latest version of API 653 into the regulations.

Detailed comments on specific ANPRM questions are included in the following sections of this response, organized by ANPRM question. For each relevant question, the Associations provide proposed revisions to the current regulations and technical and safety justification. As requested in the ANPRM, these responses also include incremental cost and benefit information available at this time. Association members continue to obtain and develop data on cost benefit for certain ANPRM topics. The Associations will submit additional data when available as a supplement to this response.

V. Specific Comments

a. Improving Repair Criteria, Remediation Timeframes and IM Regulations

Question – Section 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:

The Associations do not believe that the current repair criteria and remediation timelines for liquid pipelines strike an appropriate balance between the safety benefits provided and costs to comply. The current repair criteria and remediation timelines are antiquated, and they drive extensive excavation and repair activity that is not necessary for pipeline safety. Operators have access to data and tools that would allow them to make better, more risk-based decisions about what defects to repair and when, but the current regulations do not allow their use. By way of these comments, the Associations respectfully request that PHMSA amend the repair criteria, remediation timelines, and other requirements in Sec. 195.452(h), as detailed further below.

The IM requirements for hazardous liquid and carbon dioxide pipelines at Sec. 195.452 have not been updated substantially since their introduction in 2000. PHMSA's proposal to update regulations for repair of hazardous liquids pipelines provides the opportunity to reflect advances in inspection technology, 25 years of learning from implementing pipeline IM programs, and the industry's improved ability to detect, understand, and respond to threats to pipeline integrity.

In many instances, the current prescriptive PHMSA regulations are not based on modern engineering principles and impose significant costs without a corresponding safety benefit. Unnecessary repairs can also increase the chance of human error in the field, creating worker and public safety risks related to excavation and repair projects. Unnecessary repairs waste human and financial capital, and that waste is ultimately passed on to consumers in the form of higher energy costs.

As a general matter, the liquids industry believes that repair criteria are a necessary and effective approach to addressing pipeline integrity and safety. However, the engineering bases of those criteria must be sound and reflect modern technology and tools. The Associations request that PHMSA modify the Part 195 regulations to allow operators to adopt performance-based integrity programs based on advanced technology, engineering assessment methods, and advanced data analytics. In turn, this would allow operators to make risk-based decisions on inspection frequency and repair schedules. Industry research on pipe material strength, failure mechanisms, inspection technologies, and other advancements has improved the ability to predict the safety of pipeline operations more accurately for all feature types.

As presented below, the Associations request changes to the regulations at Sec. 195.452(h) that are grounded in advanced engineering and analytics. These changes include the following proposed revisions to the current regulations at Sec. 195.452(h):

- Modernizing the metal loss, crack and deformation repair criteria.
- Allowing operators to base repair schedules on calculations of estimated failure pressures and the remaining strength of a pipeline at anomaly locations for corrosion, metal loss and crack features and allowing the use of dent fatigue life and strain calculations to determine repair timelines for dents.
- Creating a new 1-year condition, which is a combination of the 60-day and 180-day conditions in the current regulations

The Associations' proposed revisions to the current repair criteria at Sec. 195.452(h) are set out below. The Associations propose removing the text with a strikethrough font and highlighted in yellow and propose adding the text shown in red font.

(h) ***What actions must an operator take to address integrity issues?*** —

(1) ***General requirements.*** An operator must take prompt action to address all anomalous conditions in the pipeline that the operator discovers through the integrity assessment conducted under 195.452(c) or 195.452(j) or information analysis conducted under 195.452(g) of this section. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity, as required by this part. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. An operator must comply with all other applicable requirements in this part in remediating a condition. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe and timely manner and are made so as to prevent damage to persons, property, or the environment. The calculation method(s) used for anomaly evaluation must be applicable for the range of relevant threats and be conducted by personnel that are determined by the operator to be qualified to make such decisions.

(i) ***Calculation method(s).*** An operator must, for each anomaly, select an appropriate remaining strength calculation methodology that gives consideration to anomaly type. Material property values should be relevant for the anomaly under consideration. The circumstances of the pipe parameters and anomaly type must meet the applicability criteria of the remaining strength calculation methodology selected. Remaining strength calculations may include, but are not limited to, ASME/ANSI B31G/Modified B31G, PRCI PR-3-805 (R-STRENG), PSqr, API 579-1/ASME FFS-1, Batelle NG-18 Ln-Sec and Modified Ln-Sec, PRCI MAT-8, and CorLas. Based on the remaining strength calculation, an operator will determine the requirements for remediation as indicated in 195.452(h)(4).

(ii) ***Temporary pressure reduction.*** An operator must notify PHMSA, in accordance with paragraph (m) of this section, if the operator cannot meet the schedule for evaluation and remediation required under paragraph (h)(3) of this section and cannot provide safety through a temporary reduction in operating pressure.

(iii) ***Long-term pressure reduction.*** When a pressure reduction exceeds 365 days, the operator must notify PHMSA in accordance with paragraph (m) of this section and explain the reasons for the delay. An operator must also take further remedial action to ensure the safety of the pipeline.

(2) ***Discovery of condition.*** Discovery of a condition occurs when an operator has adequate information to determine that a condition presenting a potential threat to the integrity of the pipeline exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate the 180-day interval is impracticable. If the operator believes that 180 days are impracticable to make a determination about a condition found during an assessment, the pipeline operator must notify PHMSA in accordance with paragraph (m) of this section and provide an expected date when adequate information will become available.

(3) ***Schedule for evaluation and remediation.*** An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety or environmental protection.

(4) ***~~Special r~~Requirements for scheduling remediation*** —

(i) ***Immediate repair conditions.*** An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce the operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure ~~using the formulas referenced in paragraph (h)(4)(i)(B)~~ pursuant to paragraph (h)(1)(i) of this section. If no suitable remaining strength calculation method can be identified, an operator must lower its operating pressure to 40% SMYS or implement a ~~minimum~~ 20% ~~percent or greater~~ operating pressure reduction, based on ~~actual~~ the highest operating pressure for two months prior to the date of inspection, until the anomaly is repaired. An operator must treat the following conditions as immediate repair conditions:

(A) Metal loss with depth greater than 80% of nominal wall thickness ~~regardless of dimensions~~.

(B) ~~A~~ Metal loss where a calculation of the remaining strength of the pipe in accordance with paragraph (h)(1)(i) of this section shows a predicted failure pressure less than the established maximum operating pressure at the location of the anomaly. ~~Suitable remaining strength calculation methods~~

~~include, but are not limited to, ASME/ANSI B31G (incorporated by reference, see § 195.3) and PRCI PR-3-805 (R-STRENG) (incorporated by reference, *see* § 195.3).~~

(C) Crack-like indication based on ILI data with depth greater than 70% of nominal wall thickness or with depth that exceeds the maximum depth sizing capabilities of the ILI tool.

(D) Crack-like indication where a calculation of the remaining strength of the pipe in accordance with paragraph (h)(1)(i) of this section shows a predicted failure pressure less than 1.10 times the established maximum operating pressure at the location of the anomaly.

(~~C~~E) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of ~~metal loss, cracking, or a stress riser~~ cracking, gouging, or metal loss that is determined by the operator to likely be caused by mechanical damage, unless an extended schedule is established in accordance with paragraph 195.452(h)(4)(iii) of this section.

(~~D~~F) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter, unless an extended schedule is established in accordance with paragraph 195.452(h)(4)(iii) of this section.

(~~E~~G) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

~~(ii) ***60-day conditions.*** Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 60 days of discovery of condition.~~

(ii) ***1 year conditions.*** Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 1 year of discovery of condition, unless an extended schedule is established in accordance with paragraph (h)(4)(iii) of this section:

(A) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than ~~3~~2% of the pipeline nominal diameter or ~~(~~greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12~~)~~.

(B) A dent located on the bottom of the pipeline that has any indication of ~~metal loss, cracking, or a stress riser~~ cracking, gouging, or metal loss that is determined by an operator to be caused by mechanical damage.

~~(iii) ***180-day conditions.*** Except for conditions listed in paragraph (h)(4)(i) or (ii) of this section, an operator must schedule evaluation and remediation of the following within 180 days of discovery of the condition:~~

(~~A~~C) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

~~(B) A dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).~~

(~~C~~D) A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.

(E) A dent located anywhere on the pipe with metal loss >20% in depth that is determined by the operator to be caused by corrosion and is not the result of mechanical damage to the pipeline.

(~~D~~F) A calculation of the remaining strength of the pipe in accordance with paragraph (h)(1)(i) of this section that ~~shows an operating pressure~~ has a predicted failure pressure that is less than 1.25 times the current established maximum operating pressure at the location of the anomaly. ~~Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G and PRCI PR-3-805 (R-STRENG).~~

(~~E~~G) An area of general corrosion that has a predicted failure pressure of less than 1.25 times the MOP.~~with a predicted metal loss greater than 50% of nominal wall~~.

~~(F) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.~~

~~(G) A potential crack indication that when excavated is determined to be a crack.~~

~~(H) Corrosion of or along a longitudinal seam weld.~~

(H) Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure of less than 1.25 times the MOP.

(I) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0.

(~~I~~J) A gouge ~~or groove~~ greater than 12.5% of nominal wall thickness.

(iii) ***Extended Schedule Conditions.*** To establish an extended schedule, an operator must:

(A) Conduct a time-dependent assessment for corrosion and crack features that, when considering growth mechanism and ILI depth tolerance, determines when a potential corrosion and/or crack anomaly reaches either:

1. 80% of nominal wall thickness; or,

2. A calculation of the remaining strength of the pipe in accordance with paragraph (h)(1)(i) of this section shows a predicted failure pressure of 1.10 times the established maximum operating pressure at the location of the anomaly.

(B) Conduct an Engineering Critical Assessment (ECA) for dents that considers:

1. The size, location, and when appropriate, the shape of the dent.

2. 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. A review of metal loss, 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 prior inline inspections.

4. 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. An evaluation of 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 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. 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.

(iv) ***Other conditions.*** In addition to the conditions listed in paragraphs (h)(4)(i) through (iii) of this section, an operator must evaluate any condition identified by an integrity assessment or information analysis that could impair the integrity of the pipeline, and as appropriate, schedule the condition for remediation. Appendix C of this part contains guidance concerning other conditions that an operator should evaluate.

Technical, Safety, and Economic Justification for Proposed Changes:

Technical and Safety Justification

The current repair criteria in Sec. 195.452(h) are not based on modern engineering tools and practices and do not reflect the knowledge gained through 25 years of implementing IM programs, including lessons learned from operator excavations and maintenance inspections. PHMSA's past lack of responsiveness to industry advancements in IM practices since the original IM rulemaking has created significant inefficiency in the repair process, inhibited innovation, and been a barrier to improved risk management practices. Data and evidence-based industry research has established advanced approaches and technologies for defect detection, characterization, scheduling and repair. These approaches are captured in numerous industry consensus standards and technical publications and are cited throughout these comments. Elements of many of these technical standards, including API RP 1160, API RP 1176, and API RP 1183 informed several of the Associations' proposed changes to Sec. 195.452(h). If adopted, these changes would allow operators to better predict anomaly failure pressures, more accurately estimate degradation rates, and perform engineering critical assessments (ECAs), significantly improving pipeline safety.

Criteria-specific justifications are summarized below:

Failure Pressure Calculation Methods

Since the adoption of the IM regulations in 2000, technical experts have developed several new analytical methods to more accurately determine failure pressures of corrosion and cracking anomalies. To bring in these advancements, the Associations propose amending the regulations to add Sec. 195.452(h)(1)(i) to include a non-exclusive list of additional failure pressure calculation methods. These methods would address a wider variety of feature types, beyond corrosion and the B31G and R-Streng methods.

The current IM regulations prevent the use of modern methods for calculating the remaining strength of certain types of defects. Specifically, in Sec. 195.452(h)(4)(i)(B) and Sec. 195.452(h)(4)(iii)(D), there are only two remaining strength calculation methods listed and both are limited to corrosion. While the regulations provide that other methods may be used, expanding the list to include other acceptable methods for a wider variety of feature types provides regulatory certainty for operators that additional methods are allowed.

Additional methods that operators could use include, but is not limited to the following:

- **PSqr**: This method is used for metal loss anomalies. The PSqr methodology estimates the remaining strength of corroded pipelines by calculating the pressure at which failure is predicted, using a squared pressure ratio (P^2) approach that incorporates defect geometry, material properties, and safety factors to ensure structural integrity.[21] Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[22]

- **API 579-1/ASME FFS-1**: This method is used for assessing metal loss, cracks and crack-like anomalies. API 579, Part 9 (Assessment of Crack-Flaws) provides three assessment levels and employs a Failure Assessment Diagram (FAD) approach to account for failure by fracture and by plastic collapse. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[23]

- **PRCI MAT-8**: This method is used for blunt flaws, cracks and crack-like anomalies. The Materials Assessment Tool - Version 8 (MAT-8) also employs a FAD approach. It has been recently updated to include probabilistic analysis and is under review for inclusion in API 579-1/ASME FFS-1. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[24]

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[21] *See e.g.,* Mohammad Al-Amin ET AL., *Achieving Consistent Safety by Using Appropriate Safety Factors in Corrosion Management Program*, *in* 1 PROC. OF THE 2020 13TH INT'L PIPELINE CONF., PIPELINE AND FACILITIES INTEGRITY (2020).

[22] *See e.g.,* Shahani Kariyawasam, Shenwei Zhang, Jason Yan, Terry Huang, Mohammad Al-Amin, & Erwin Gamboa, Plausible Profiles (Psqr) corrosion assessment model (2020).

[23] *See e.g.,* Andrew Cosham & Phil Hopkins, *The Pipeline Defect Assessment Manual, in* PROC. OF THE 2002 4TH INT'L PIPELINE CONF., 1565 (2002); Ted L. Anderson & David A. Osage, Am. Petroleum Inst., *API 579: A comprehensive fitness-for-service guide*, *in* 77 Int'l J. of Pressure Vessels and Piping, 953 (2000).

[24] *See e.g.,* Ted L. Anderson, Pipeline Rsch. Council Int'l, *Assessing Crack-Like Flaws in Longitudinal Seam Weld: A State-of-the-Art Review* (2017); Thomas Dessein ET AL., *Burst Pressure Prediction for Axial Cracks in Pipelines With Non-Ideal Depth Profiles, in* 2B PROC. OF THE 2024 15TH INT'L PIPELINE CONF., PIPELINE AND FACILITIES INTEGRITY (2024).

- **CorLAS:** CorLAS (Corrosion Life Assessment Software) was developed for the assessment of sharp, longitudinally orientated surface flaws in a cylinder subject to internal pressure (i.e. axial cracks). It includes empirical correlations between the J-integral and the yield and tensile strength and Charpy V-notch impact energy) derived from tests on pipeline steels. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[25]

- **Batelle NG-18 Ln-Sec and Modified Ln-Sec**: This method is used for axially oriented surface anomalies. NG-18 is a semi-empirical model for predicting the failure stress of a pressurized cylinder with a longitudinal crack like defect. Industry experience with this method demonstrates that it may not be appropriate for all circumstances, particularly for pipe seams with a seam joint factor less than 1 that operate in the brittle regime but may be used for pipelines operating within the ductile regime.[26]

The Associations have also proposed added safety margins of 1.25x MOP when conducting remaining strength calculations under certain proposed 1-year conditions. The Associations based this safety margin on PRCI research[27] and expected changes to RP 1176.[28]

Repair Criteria for Corrosion

The Associations propose updates to Sec. 195.452(h) repair criteria for corrosion features to focus those criteria on risk. First, the Associations propose a 1.25 safety factor rather than a factor of 1.39 for metal loss anomalies that qualify as 1-year conditions. The original rationale for a 1.39 safety factor is that it is the reciprocal of the 0.72 design factor in Sec. 195.106. The 0.72 design factor was intended to account for material uncertainties and allowable defects in the construction of a pipeline, including defects allowed by API 5L.[29]

However, when operators perform failure pressure calculations, there is an implicit requirement to consider defect sizes and uncertainties within those evaluations, so the combination of a 1.39 safety

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[25] *See e.g.,* Ahmed Sellami ET AL., *Strain-Based Modeling of Burst Pressure in Pipelines with Selective Seam Weld Corrosion*, 217 Int'l J. of Pressure Vessels and Piping (2025); Raymond R. Fessler ET AL., *Predicting the Failure Pressure of SCC Flaws in Gas Transmission Pipelines, in* 2 PROC. OF THE 2012 9TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT 653 (2012).

[26] *See e.g.,* Andrew Cosham ET AL., *Crack-Like Defects in Pipelines: The Relevance of Pipeline-Specific Methods and Standards, in* 2 PROC. OF THE 2012 9TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT 713 (2012); Samarth Tandon ET AL., *Evaluation of Existing Fracture Mechanics Models for Burst Pressure Predictions, Theoretical and Experimental Aspects*, *in* 2 PROC. OF THE 2014 10TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT (2014).

[27] *See* Cara Macrory, Pipeline Rsch. Council Int'l, *Considerations for Crack ILI Response in Hazardous Liquids Pipelines* (2022).

[28] Am. Petroleum Inst., Recommended Practice 1176: Assessment and Management of Cracking in Pipelines, (1st ed. 2016). The second edition of API RP 1176 is expected in late 2025 or early 2026.

[29] API 5L is also incorporated by reference into Part 195. 49 CFR § 195.3(b)(12).

factor with this more detailed assessment is unnecessary and duplicative. The change from this unnecessarily conservative approach to a more reasonable 1.25 safety factor is also supported in modern industry standards. For example, the ASME B31.G failure pressure calculation method for corrosion was updated in 2012 to allow a safety factor of 1.25. The use of a 1.25 safety factor for metal loss anomalies is also consistent with API RP 1160.

The Associations' proposed revisions to the response criteria for corrosion based on failure pressure calculations are also appropriate because they would reduce unnecessary excavation and repair activities. Reducing unnecessary projects not only conserves resources but it also reduces the risk of human error involved in any project, thereby reducing worker and public safety risks. In addition, many pipelines have undergone multiple ILI runs that have provided a large amount of data and information on pipeline condition allowing for estimations of corrosion growth rates. Given this understanding it is unlikely that a general corrosion condition on a pipeline with a safety factor of above 1.25 will pose a threat to the integrity of a pipeline within a one-year timeframe of discovery. Moreover, for anomalies with burst pressures above 1.25x MOP, operators remain subject to the IM repair catch-all requirement[30] to schedule repairs as necessary based on an integrity assessment under Sec. 195.452(j) or an information analysis under Sec. 195.452(g). Thus, if other information about risk indicates the need to repair an anomaly it must be scheduled for repair.

In addition to the 1.25 safety factor, the Associations also propose revisions to repair criteria related to longitudinal seam weld corrosion. The current response criterion in Sec. 195.452(h)(4)(iii)(H) requires repair of "corrosion of or along a longitudinal seam weld," which has been interpreted by PHMSA[31] to require repair of any corrosion anomaly that intersects or is close to a longitudinal seam weld. However, industry experience indicates that most corrosion on or near the longitudinal seam does not represent a threat to pipeline integrity. This has resulted in thousands of unwarranted anomaly repair excavations, resulting in millions of dollars of repair costs that provide little safety benefit. PHMSA has recognized this issue in recent changes to the repair criteria for gas transmission lines.[32] The Association's proposed amendments mirror the Part 192 revisions and define the relevant corrosion as metal loss that may be "preferentially affecting a longitudinal seam." This change would ensure that resources are focused on conditions that represent a threat to pipeline integrity. The proposed changes also reflect the language that is currently applicable to gas pipelines in Sec. 192.714 and Sec.192.933.[33]

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[30] 49 C.F.R. § 195.452(h)(1).

[31] Letter of Interpretation from John A. Gale, Director of Office Standards and Rulemaking, PHMSA, to Mr. Wm. Dean Gore, Jr., Vice President, Environmental & Regulatory Compliance, Plains All American GP LLC, PI-17-0014 (Apr. 26, 2018), https://www.phmsa.dot.gov/regulations/title49/interp/pi-17-0014.

[32] For the amendments to the gas repair criteria, PHMSA noted that "[c]orrosion that 'preferentially' affects the long seam is corrosion that is of and along the weld seam that is classified as selective seam weld corrosion." Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, 87 Fed. Reg. 52,224, 52,250 (Aug. 24, 2022).

[33] 49 C.F.R. § 192.714(d)(2)(vi), (d)(3)(v); 49 C.F.R. § 192.933(d)(2)(v), (d)(3)(v).

Repair Criteria for Cracks

The Associations propose revisions to Sec. 195.452(h)(4) repair criteria to include more specific crack response criteria for immediate repair conditions and 1-year crack response criteria for less severe cracks, based on failure pressure ratio calculations. Technology and engineering methods related to crack threats have advanced significantly since the original promulgation of the IM rules, and the Associations' proposed repair criteria for cracks capture those advancements, including two new immediate repair conditions for crack anomalies detected by ILI.

The Associations propose the use of a 1.25 safety factor for crack anomalies that qualify as one-year conditions. A 1.25 safety factor is well supported by industry research, experience and technical resources like API RP 1176 and TR 1190.[34] Specifically, TR 1190 demonstrates that there is little safety benefit in moving from a safety factor of 1.25 to 1.39.[35] Both of these standards informed the Association's proposed repair criteria for cracking threats.

Operator data and evidence-based industry research has found the repair criteria outlined in API TR 1190 to provide sufficient safeguards to protect the public. The criteria in TR 1190 are consistent with key elements of Part 195 Subparts E and F, Part 192 response criteria, API RP 1160, API RP 1176, CSA Z662, ASME B31.4, and STP-PT-011. A PRCI project[36] derived the optimal crack ILI response criteria for hazardous liquid pipelines, and the findings from this work formed the basis of API TR 1190 and elements of the pending release of API RP 1176, 2nd edition. Basing the IM cracking repair criteria on these criteria will set uniform standards, improve efficiency and help protect the public and the environment.

Repair Criteria for Dents and Dents With Metal Loss

The Associations propose new dent repair criteria which include immediate and 1-year conditions based on significant advancements in the understanding of dents. The immediate repair conditions target features that represent higher likelihoods of being injurious, or which may be related to severe mechanical damage. The 1-year conditions include dents that show industry-recognized risk factors that should be investigated, but which do not present an immediate safety threat. In addition, the Associations propose an alternate criterion that involves performing an ECA to determine if alternate repair timelines are appropriate for dents that otherwise fit into the new immediate and 1-year criteria.

The Associations propose this ECA alternative to the prescriptive repair criteria for dents because it is well understood that the specific shape of a dent and operating conditions affect its level of

[34] Am. Petroleum Inst., Recommended Practice 1176: Assessment and Management of Cracking in Pipelines, (1st ed. 2016); Am. Petroleum Inst., Technical Report 1190: Crack ILI Response: Maximum Depth and Failure Pressure Ratio, (1st ed. 2024)..

[35] Am. Petroleum Inst., Technical Report 1190: Crack ILI Response: Maximum Depth and Failure Pressure Ratio at 3, (1st ed. 2024).

[36] Cara Macrory, Pipeline Rsch. Council Int'l, *Considerations for Crack ILI Response in Hazardous Liquids Pipelines* (2022).

risk. Dent shape and operating conditions allow for a more accurate determination of risk than using just dent depth.

The introduction of the first edition of API RP 1183 in 2020 provided a holistic framework for the management of pipeline dents and was an important milestone for the industry. [37] A key part of pipeline dent management in API 1183 is the understanding that tiered ECAs (or fitness for service) are possible and may rely on multiple methods.

The Associations' proposed ECA language provides a framework that operators may use to supplement the proposed prescriptive dent repair criteria. Dent ECAs may require robust data integration and use safety factors to account for loading, model, measurement, and material uncertainties. These elements are included in the Associations' proposed ECA language and are built on integrity management principles in accepted industry standards, including ASME B31.8S[38] and API 1160.[39]

The ECA methods in API 1183 are based on decades of pipeline industry experience and show that ECA processes for a dent should consider two types of assessments, fatigue and strain-based evaluations.

- Strain-based evaluations are recognized by the industry and have appeared in ASME B31.8 for over two decades (non-mandatory appendix R of ASME B31.8 and in CSA-Z662). Strain-based methods have continued to evolve and there has been significant work in this area in recent years to account for more parameters and uncertainties.[40] Strain-based evaluations are a key part of dent assessments.

- Fatigue based evaluations are a key part of dent assessments and industry papers and projects have developed technical methods and validation for many of the commonly used fatigue-based methods. Notably, PRCI reports show the amount of work that went into development of just one of the methods presented in API RP 1183.[41] Additionally, validation work using full scale fatigue testing of field dents presented in additional PRCI research exemplifies how these methods are being validated and improved through organizations like PRCI.[42] Many other individual papers have been published with respect

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[37] Am. Petroleum Inst., Recommended Practice 1183: Assessment and Management of Pipeline Dents (1st ed. 2020).

[38] The Am. Soc'y of Mech. Eng'r, B31.8S - Managing System Integrity of Gas Pipelines, (2022).

[39] Am. Petroleum Inst., Recommended Practice 1160, Managing System Integrity for Hazardous Liquid Pipelines (3rd ed. 2019, reaffirmed 2024)

[40] *See* Arnav Rana ET AL., Pipeline Rsch. Council Int'l, *Improve Dent-Cracking Assessment Methods* (2022).

[41] *See* Sanjay Tiku ET AL., Pipeline Rsch. Council Int'l, *Fatigue Life Assessment of Dents with and without Interacting Features*; Sanjay Tiku, Pipeline Rsch. Council Int'l, *Improvement in Dent Assessment and Management Tools* (2024).

[42] *See* PRCI MD-4-15, Performance of Dent Fatigue Models for Natural Dents Removed from Service.

to other fatigue methods.[43] Ultimately, fatigue-based evaluations are a key part of dent assessments.

The presence of interacting features (e.g., metal loss, gouges, cracks etc.) may impact the results of the strain and fatigue assessments of dents. Operators have also investigated the ability of ILI to provide information about interacting threats via large PRCI projects.[44] Key findings from these projects show that the uncertainties in measurement (POD and sizing) are generally on the same order as what is accepted for stand-alone features such as metal loss or cracks. The presence and integrity impact of these features can be accounted for in assessments. Additionally, advancements in ILI technology and analysis have made it possible to identify gouging and mechanical damage related metal loss during inspections.[45] Operators also have access to multiple inline inspection data sets, right-of-way surveillance, and depth cover information that can be used for robust data integration to identify mechanical damage features.

Cost Justification

By targeting excavations where repair is needed, the Association expect that there will be a reduction in the number of digs performed to fix non-injurious anomalies – focusing resources on risk and rechanneling remaining resources to other actions that have an improved safety benefit.

Cracks

The Associations will provide cost information regarding anticipated cost savings for its proposed crack criteria updates in a subsequent filing.

Corrosion

The Associations' proposed changes to the corrosion repair criteria are expected to result in significant cost savings associated with avoiding excavations and repairs that are not necessary for safety. To provide a specific example, ILI technologies have improved substantially and can now provide data that allows operators to differentiate corrosion intersecting a longitudinal seam (which is often not a threat to integrity) versus metal loss that is preferentially affecting the longitudinal seam.

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[43] *See* R. L. Dotson ET AL., *Combining High Resolution In-Line Geometry Tools and Finite Element Analysis to Improve Dent Assessments*, Paper No. PPIM-ILI2-16, PROC. OF THE PIPELINE PIGGING AND INTEGRITY MANAGEMENT CONFERENCE (2014).

[44] Arnav Rana & Sanjay Tiku, Pipeline Rsch. Council Int'l, *Verification of Screening Tools for Classifying ILI Reported Dents with Metal Loss Features* (2023); Sanjay Tiku, Pipeline Rsch. Council Int'l, *Performance Evaluation of ILI Systems for Dents and Coincident Features* (2024), https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=20257&s=5B6EAFBE26AB49FA93493ACD715FF3AE&c=1.

[45] Matt Romney, Dane Burden & Mike Kirkwood, *The Power to Know More About Third Party Gouging, in* PROC. OF THE PIPELINE TECHNOLOGY CONF. (2022).

The Associations sought information from their members on excavations to comply with the current criteria for corrosion. In a useful example of criteria that do not drive safety improvement, two operators provided information on 2700 digs conducted pursuant to the long-seam corrosion criteria at Sec. 195.452(h)(4)(iii)(H) on two different pipeline systems totaling 6000 anomalies investigated. The results of these investigations found incidental corrosion features crossing or near the long seam weld but showed no evidence of preferential attack of the long seam weld. This effort resulted in an estimated **$135MM** spent with very little improvement in pipeline safety.

Dents

The Associations' proposed dent criteria would reduce costs by eliminating unnecessary excavations driven by the current, arbitrary dent depth criteria. The Associations propose to keep the depth-based criteria for dents but also allow operators the option apply modern ECA methods to determine if dents are a threat to pipeline integrity. One operator informed the Associations it would save **$1+ million annually** if it were permitted to use the Association's proposed dent criteria.

b. Accommodating Innovative Technologies and Methods

Question – Section 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:

Incentivizing New Assessment Tool Technology

The Associations believe that Sec. 195.452 inhibits operators from testing certain innovative ILI technologies. Current regulations do not specifically prevent operators or ILI vendors from developing new assessment technologies, or from testing new tools on their systems. However, PHMSA has interpreted Sec. 195.452(h)(1) to require operators to action data from any pipeline assessment,[46] including when testing new tools in their systems, even where that tool data has not been validated. This results in operator and vendor hesitancy in adopting new ILI technology

[46] PHMSA, *Liquid Integrity Management Rule Frequently Asked Questions*, at FAQ 7.21 (Aug. 31, 2016), https://www.phmsa.dot.gov/pipeline/hazardous-liquid-integrity-management/hl-im-faqs.

because early uncertainty in defect detection, sizing and other parameters may lead to large numbers of false positive results that must be excavated. Several of the Associations' members shared that the current, prescriptive nature of the IM rules had inhibited them from trialing innovative technology.

Evaluating new ILI technologies is an iterative process that involves evaluating tool data, field NDE data from confirmatory digs, and pipeline segment physical and operational characteristics. These efforts help operators understand whether an ILI tool is providing accurate data. Until the accuracy of any given tool can be confirmed, operators should not be required to make repairs based on the data from that tool. Operators should be allowed to make an engineering determination about the reliability of tool data for new ILI tools, before they are required to action that data.

The Associations propose that PHMSA amend Sec. 195.416 and Sec. 195.452 to allow for more flexibility when testing new tools. Such changes could spur increased development of inspection technologies. These proposed changes are also consistent with industry recommendations related to PHMSA's Technology Pilot Program (approved in the 2020 PIPES Act) where new technologies could be evaluated under certain conditions. While the industry advocated for the technology pilot program, PHMSA's approval process for approving technology pilots was so onerous that no operators have successfully used that program.

Proposed Changes to Part 195

49 CFR § 195.416

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(i) ***Research & Development***. An operator is exempt from the requirements of 195.416 for a pipeline assessment or reporting that is performed for research and development purposes. If the operator designates a pipeline assessment as an R&D effort it cannot be used as an initial or periodic assessment under 195.416(b).

49 CFR § 195.452

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(o) ***Research & Development***. An operator is exempt from the requirements of 195.452 for a pipeline assessment or reporting that is performed for research and development purposes. If the operator designates a pipeline assessment as an R&D effort it cannot be used as a baseline assessment under 195.452(c) or reassessment under 195.452(j).

Update List of Evaluation Methods

The current IM regulations also prevent the use of modern methods for calculating the remaining strength of certain types of defects. Specifically, in Sec. 195.452(h)(4)(i)(B) and Sec. 195.452(h)(4)(iii)(D), there are only two remaining strength calculation methods listed. While the regulations provide that other methods may be used, expanding the list to include other acceptable methods provides regulatory certainty for operators that these methods may be used. In addition, the two currently referenced methods are only applicable to corrosion anomalies. Since the adoption of the IM regulations in 2000, technical experts have developed several new analytical methods to more accurately determine failure pressure and other features of anomalies. As also addressed in the response to ANPRM Question III.A.1, the Associations propose a new Sec. 195.452(h)(1)(i), which sets out a non-exclusive list of failure pressure calculation methods.

Additional methods, beyond B31G and R-Streng include the following:

- **PSqr**: This method is used for metal loss anomalies. The PSqr methodology estimates the remaining strength of corroded pipelines by calculating the pressure at which failure is predicted, using a squared pressure ratio (P^2) approach that incorporates defect geometry, material properties, and safety factors to ensure structural integrity.[47] Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[48]

- **API 579-1/ASME FFS-1**: This method is used for assessing metal loss, cracks and crack-like anomalies. API 579 Part 9 (Assessment of Crack-Flaws) provides three assessment levels and employs a Failure Assessment Diagram (FAD) approach to account failure by fracture and by plastic collapse. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[49]

- **PRCI MAT-8**: This method is used for blunt flaws, cracks and crack-like anomalies. The Materials Assessment Tool - Version 8 (MAT-8) also employs a FAD approach. It has been recently updated to include probabilistic analysis and is under review for inclusion in API 579-1/ASME FFS-1. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[50]

- **CorLAS:** CorLAS (Corrosion Life Assessment Software) was developed for the assessment of sharp, longitudinally orientated surface flaws in a cylinder subject to internal pressure (i.e. axial cracks). It includes empirical correlations between the J-integral and the yield

[47]*See e.g.,* Mohammad Al-Amin ET AL., *Achieving Consistent Safety by Using Appropriate Safety Factors in Corrosion Management Program*, *in* 1 PROC. OF THE 2020 13TH INT'L PIPELINE CONF., PIPELINE AND FACILITIES INTEGRITY (2020).

[48] *See e.g.,* Shahani Kariyawasam, Shenwei Zhang, Jason Yan, Terry Huang, Mohammad Al-Amin, & Erwin Gamboa, Plausible Profiles (Psqr) corrosion assessment model (2020).

[49] *See e.g.,* Andrew Cosham & Phil Hopkins, *The Pipeline Defect Assessment Manual, in* PROC. OF THE 2002 4TH INT'L PIPELINE CONF., 1565 (2002); Ted L. Anderson & David A. Osage, Am. Petroleum Inst., *API 579: A comprehensive fitness-for-service guide*, *in* 77 Int'l J. of Pressure Vessels and Piping, 953 (2000).

[50]*See e.g.,* Ted L. Anderson, Pipeline Rsch. Council Int'l, Assessing Crack-Like Flaws in Longitudinal Seam Weld: A State-of-the-Art Review (2017); Thomas Dessein ET AL., Burst Pressure Prediction for Axial Cracks in Pipelines With Non-Ideal Depth Profiles, in 2B PROC. OF THE 2024 15TH INT'L PIPELINE CONF., PIPELINE AND FACILITIES INTEGRITY (2024).

and tensile strength and Charpy V-notch impact energy) derived from tests on pipeline steels. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[51]

- **Batelle NG-18 Ln-Sec and Modified Ln-Sec**: This method is used for axially oriented surface anomalies. NG-18 is a semi-empirical model for predicting the failure stress of a pressurized cylinder with a longitudinal crack like defect. Industry experience with this method demonstrates that it may not be appropriate for all circumstances, particularly for pipe seams with a seam joint factor less than 1 that operate in the brittle regime but may be used for pipelines operating within the ductile regime.[52]

Proposed Changes to Part 195:

195.452(h)(1)

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(i) ***Calculation method(s).*** An operator must, for each anomaly, select an appropriate remaining strength calculation methodology that gives consideration to anomaly type. Material property values should be relevant for the anomaly under consideration. The circumstances of the pipe parameters and anomaly type must meet the applicability criteria of the remaining strength calculation methodology selected. Remaining strength calculations may include, but are not limited to, ASME/ANSI B31G/Modified B31G, PRCI PR-3-805 (R-STRENG), PSqr, API 579-1/ASME FFS-1, Batelle NG-18 Ln-Sec and Modified Ln-Sec, PRCI MAT-8, and CorLas. Based on the remaining strength calculation, an operator will determine the requirements for remediation as indicated in 195.452(h)(4).

Note: These proposed updated calculation methods are part of the Associations' larger proposal to amend Sec. 195.452(h), set out in full in response to question III.A.1.

Technical, Safety, and Economic Justification for Proposed Changes:

Incentivizing New Assessment Tool Technology

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[51] *See e.g.,* Ahmed Sellami ET AL., *Strain-Based Modeling of Burst Pressure in Pipelines with Selective Seam Weld Corrosion*, 217 Int'l J. of Pressure Vessels and Piping (2025); Raymond R. Fessler ET AL., *Predicting the Failure Pressure of SCC Flaws in Gas Transmission Pipelines, in* 2 PROC. OF THE 2012 9TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT 653 (2012).

[52] *See e.g.,* Andrew Cosham ET AL., *Crack-Like Defects in Pipelines: The Relevance of Pipeline-Specific Methods and Standards, in* 2 PROC. OF THE 2012 9TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT 713 (2012); Samarth Tandon ET AL., *Evaluation of Existing Fracture Mechanics Models for Burst Pressure Predictions, Theoretical and Experimental Aspects*, *in* 2 PROC. OF THE 2014 10TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT (2014).

Including a regulatory provision that allows for research and development activities associated with in-line inspection technology will encourage innovation. Providing this research and development safe harbor will also avoid the potentially significant cost of excavating indications based on tool data that has not been validated and may drive false positives.

Update List of Evaluation Methods

Updating the list of remaining strength calculations will allow operators to take advantage of the innovations operators have made in the pipeline integrity space in the past 25 years. These new analytical methods more accurately determine the failure pressure of anomalies and are the foundation for operators to use risk-based methods to manage their pipelines in a safe and cost-effective manner. Extensive technical documentation, as cited in the preceding section, supports the use of these methods.

c. Use of Risk-Based Repair Criteria

Question – Section 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:

The Associations recognize that certain prescriptive repair criteria and remediation timeframes are appropriate for some types of anomalies. Indeed, the Associations proposed updates to Sec. 195.452(h) retain several prescriptive criteria and add more immediate repair conditions for certain crack threats. However, prescriptive repair criteria often require repairs of anomalies that a more detailed analysis reveal can be safely monitored. Operators can now utilize modern ILI tools and engineering analysis to safely manage anomalies where the current regulations do not provide that flexibility. Given those advancements in technology, the Associations propose that operators have the option to apply modern defect failure pressure calculation methods and ECA tools to further evaluate defects to determine if they need to be repaired. The Associations provided detailed comments on the topic of prescriptive repair criteria in response to ANPRM Question III.A.1, above. That content is repeated below.

<u>Proposed Changes to Part 195:</u>

(h) ***What actions must an operator take to address integrity issues? —***

(1) ***General requirements.*** An operator must take prompt action to address all anomalous conditions in the pipeline that the operator discovers through the integrity assessment conducted under 195.452(c) or 195.452(j) or information analysis conducted under 195.452(g) of this section. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity, as required by this part. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. An operator must comply with all other applicable requirements in this part in remediating a condition. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe and timely manner and are made so as to prevent damage to persons, property, or the environment. The calculation method(s) used for anomaly evaluation must be applicable for the range of relevant threats and be conducted by personnel that are determined by the operator to be qualified to make such decisions.

(i) ***Calculation method(s).*** An operator must, for each anomaly, select an appropriate remaining strength calculation methodology that gives consideration to anomaly type. Material property values should be relevant for the anomaly under consideration. The circumstances of the pipe parameters and anomaly type must meet the applicability criteria of the remaining strength calculation methodology selected. Remaining strength calculations may include, but are not limited to, ASME/ANSI B31G/Modified B31G, PRCI PR-3-805 (R-STRENG), PSqr, API 579-1/ASME FFS-1, Batelle NG-18 Ln-Sec and Modified Ln-Sec, PRCI MAT-8, and CorLas. Based on the remaining strength calculation, an operator will determine the requirements for remediation as indicated in 195.452(h)(4).

(ii) ***Temporary pressure reduction.*** An operator must notify PHMSA, in accordance with paragraph (m) of this section, if the operator cannot meet the schedule for evaluation and remediation required under paragraph (h)(3) of this section and cannot provide safety through a temporary reduction in operating pressure.

(iii) ***Long-term pressure reduction.*** When a pressure reduction exceeds 365 days, the operator must notify PHMSA in accordance with paragraph (m) of this section and explain the reasons for the delay. An operator must also take further remedial action to ensure the safety of the pipeline.

(2) ***Discovery of condition.*** Discovery of a condition occurs when an operator has adequate information to determine that a condition presenting a potential threat to the integrity of the pipeline exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate the 180-day interval is impracticable. If the operator believes that 180 days are impracticable to make a determination about a condition found during an assessment, the pipeline operator must notify PHMSA in accordance with paragraph (m) of this section and provide an expected date when adequate information will become available.

(3) ***Schedule for evaluation and remediation.*** An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety or environmental protection.

(4) ***~~Special r~~Requirements for scheduling remediation*** —

(i) ***Immediate repair conditions.*** An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce the operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure ~~using the formulas referenced in paragraph (h)(4)(i)(B)~~ pursuant to paragraph (h)(1)(i) of this section. If no suitable remaining strength calculation method can be identified, an operator must lower its operating pressure to 40% SMYS or implement a ~~minimum~~ 20% ~~percent or greater~~ operating pressure reduction, based on ~~actual~~ the highest operating pressure for two months prior to the date of inspection, until the anomaly is repaired. An operator must treat the following conditions as immediate repair conditions:

(A) Metal loss with depth greater than 80% of nominal wall thickness ~~regardless of dimensions~~.

(B) ~~A~~ Metal loss where a calculation of the remaining strength of the pipe in accordance with paragraph (h)(1)(i) of this section shows a predicted failure pressure less than the established maximum operating pressure at the location of the anomaly. ~~Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (incorporated by reference, see § 195.3) and PRCI PR-3-805 (R-STRENG) (incorporated by reference, *see* § 195.3).~~

(C) Crack-like indication based on ILI data with depth greater than 70% of nominal wall thickness or with depth that exceeds the maximum depth sizing capabilities of the ILI tool.

(D) Crack-like indication where a calculation of the remaining strength of the pipe in accordance with paragraph (h)(1)(i) of this section shows a predicted failure pressure less than 1.10 times the established maximum operating pressure at the location of the anomaly.

(~~C~~E) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of ~~metal loss, cracking, or a stress riser~~ cracking, gouging, or metal loss that is determined by the operator to likely be caused by mechanical damage, unless an extended schedule is established in accordance with paragraph 195.452(h)(4)(iii) of this section.

(~~D~~F) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter, unless an extended schedule is established in accordance with paragraph 195.452(h)(4)(iii) of this section.

(~~E~~G) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

~~(ii) ***60-day conditions.*** Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 60 days of discovery of condition.~~

(ii) ***1 year conditions.*** Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 1 year of discovery of condition, unless an extended schedule is established in accordance with paragraph (h)(4)(iii) of this section:

(A) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than ~~3~~2% of the pipeline nominal diameter or ~~(~~greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12~~)~~.

(B) A dent located on the bottom of the pipeline that has any indication of ~~metal loss, cracking, or a stress riser~~ cracking, gouging, or metal loss that is determined by an operator to be caused by mechanical damage.

~~(iii) ***180-day conditions.*** Except for conditions listed in paragraph (h)(4)(i) or (ii) of this section, an operator must schedule evaluation and remediation of the following within 180 days of discovery of the condition:~~

(~~A~~C) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

~~(B) A dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).~~

(~~C~~D) A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.

(E) A dent located anywhere on the pipe with metal loss >20% in depth that is determined by the operator to be caused by corrosion and is not the result of mechanical damage to the pipeline.

(~~D~~F) A calculation of the remaining strength of the pipe in accordance with paragraph (h)(1)(i) of this section that ~~shows an operating pressure~~ has a predicted failure pressure that is less than 1.25 times the current established maximum operating pressure at the location of the anomaly. ~~Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G and PRCI PR-3-805 (R-STRENG).~~

(~~E~~G) An area of general corrosion that has a predicted failure pressure of less than 1.25 times the MOP.~~with a predicted metal loss greater than 50% of nominal wall~~.

~~(F) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.~~

~~(G) A potential crack indication that when excavated is determined to be a crack.~~

~~(H) Corrosion of or along a longitudinal seam weld.~~

(H) Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure of less than 1.25 times the MOP.

(I) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0.

(~~I~~J) A gouge ~~or groove~~ greater than 12.5% of nominal wall thickness.

(iii) ***Extended Schedule Conditions.*** To establish an extended schedule, an operator must:

(A) Conduct a time-dependent assessment for corrosion and crack features that, when considering growth mechanism and ILI depth tolerance, determines when a potential corrosion and/or crack anomaly reaches either:

1. 80% of nominal wall thickness; or,
2. A calculation of the remaining strength of the pipe in accordance with paragraph (h)(1)(i) of this section shows a predicted failure pressure of 1.10 times the established maximum operating pressure at the location of the anomaly.

(B) Conduct an Engineering Critical Assessment (ECA) for dents that considers:

1. The size, location, and when appropriate, the shape of the dent.
2. 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. A review of metal loss, 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 prior inline inspections.
4. 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. An evaluation of 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 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. 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.

(iv) ***Other conditions.*** In addition to the conditions listed in paragraphs (h)(4)(i) through (iii) of this section, an operator must evaluate any condition identified by an integrity assessment or information analysis that could impair the integrity of the pipeline, and as appropriate, schedule the condition for remediation. Appendix C of this part contains guidance concerning other conditions that an operator should evaluate.

Technical, Safety, and Economic Justification for Proposed Changes:

Technical and Safety Justification

The current repair criteria in Sec. 195.452(h) are not based on modern engineering tools and practices and do not reflect the knowledge gained through 25 years of implementing IM programs, including lessons learned from operator excavations and maintenance inspections. PHMSA's past lack of responsiveness to industry advancements in IM practices since the original IM rulemaking has created significant inefficiency in the repair process, inhibited innovation, and been a barrier to improved risk management practices. Data and evidence-based industry research has established advanced approaches and technologies for defect detection, characterization, scheduling and repair. These approaches are captured in numerous industry consensus standards and technical publications and are cited throughout these comments. Elements of many of these technical standards, including API RP 1160, API RP 1176, and API RP 1183 informed several of the Associations' proposed changes to Sec. 195.452(h). If adopted, these changes would allow operators to better predict anomaly failure pressures, more accurately estimate degradation rates, and perform engineering critical assessments (ECAs), significantly improving pipeline safety.

Repair-criteria specific justifications are summarized below:

Failure Pressure Calculation Methods

Since the adoption of the IM regulations in 2000, technical experts have developed several new analytical methods to more accurately determine failure pressure of corrosion and cracking anomalies. To bring in these advancements, the Associations propose amending the regulations to add Sec. 195.452(h)(1)(i) to include a non-exclusive list of additional failure pressure calculation methods. These methods would address a wider variety of feature types, beyond corrosion and the B31G and R-Streng methods.

The current IM regulations prevent the use of modern methods for calculating the remaining strength of certain types of defects. Specifically, in Sec. 195.452(h)(4)(i)(B) and Sec. 195.452(h)(4)(iii)(D), there are only two remaining strength calculation methods listed, and both are limited to corrosion. While the regulations provide that other methods may be used, expanding the list to include other acceptable methods for a wider variety of feature types provides regulatory certainty for operators that additional methods are allowed.

Additional methods that operators could use include, but is not limited to the following:

- **PSqr**: This method is used for metal loss anomalies. The PSqr methodology estimates the remaining strength of corroded pipelines by calculating the pressure at which failure is predicted, using a squared pressure ratio (P^2) approach that incorporates defect geometry, material properties, and safety factors to ensure structural integrity.[53] Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[54]

- **API 579-1/ASME FFS-1**: This method is used for assessing metal loss, cracks and crack-like anomalies. API 579, Part 9 (Assessment of Crack-Flaws) provides three assessment levels and employs a Failure Assessment Diagram (FAD) approach to account for failure by fracture and by plastic collapse. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[55]

- **PRCI MAT-8**: This method is used for blunt flaws, cracks and crack-like anomalies. The Materials Assessment Tool - Version 8 (MAT-8) also employs a FAD approach. It has been recently updated to include probabilistic analysis and is under review for inclusion in API 579-1/ASME FFS-1. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[56]

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[53]*See e.g.,* Mohammad Al-Amin ET AL., *Achieving Consistent Safety by Using Appropriate Safety Factors in Corrosion Management Program*, *in* 1 PROC. OF THE 2020 13TH INT'L PIPELINE CONF., PIPELINE AND FACILITIES INTEGRITY (2020).

[54] *See e.g.,* Shahani Kariyawasam, Shenwei Zhang, Jason Yan, Terry Huang, Mohammad Al-Amin, & Erwin Gamboa, Plausible Profiles (Psqr) corrosion assessment model (2020).

[55] *See e.g.,* Andrew Cosham & Phil Hopkins, *The Pipeline Defect Assessment Manual, in* PROC. OF THE 2002 4TH INT'L PIPELINE CONF., 1565 (2002); Ted L. Anderson & David A. Osage, Am. Petroleum Inst., *API 579: A comprehensive fitness-for-service guide*, *in* 77 Int'l J. of Pressure Vessels and Piping, 953 (2000).

[56]*See e.g.,* Ted L. Anderson, Pipeline Rsch. Council Int'l, *Assessing Crack-Like Flaws in Longitudinal Seam Weld: A State-of-the-Art Review* (2017); Thomas Dessein ET AL., *Burst Pressure Prediction for Axial Cracks in Pipelines With Non-Ideal Depth Profiles, in* 2B PROC. OF THE 2024 15TH INT'L PIPELINE CONF., PIPELINE AND FACILITIES INTEGRITY (2024).

- **CorLAS:** CorLAS (Corrosion Life Assessment Software) was developed for the assessment of sharp, longitudinally orientated surface flaws in a cylinder subject to internal pressure (i.e. axial cracks). It includes empirical correlations between the J-integral and the yield and tensile strength and Charpy V-notch impact energy) derived from tests on pipeline steels. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[57]

- **Batelle NG-18 Ln-Sec and Modified Ln-Sec**: This method is used for axially oriented surface anomalies. NG-18 is a semi-empirical model for predicting the failure stress of a pressurized cylinder with a longitudinal crack like defect. Industry experience with this method demonstrates that it may not be appropriate for all circumstances, particularly for pipe seams with a seam joint factor less than 1 that operate in the brittle regime, but may be used for pipelines operating within the ductile regime.[58]

The Associations have also proposed added safety margins of 1.25x MOP when conducting remaining strength calculations under certain proposed 1-year conditions. The Associations based this safety margin on PRCI research[59] and expected changes to RP 1176.[60]

Repair Criteria for Corrosion

The Associations propose updates to Sec. 195.452(h) repair criteria for corrosion features to focus those criteria on risk. First, the Associations propose a 1.25 safety factor rather than a factor of 1.39 for metal loss anomalies that qualify as 1-year conditions. The original rationale for a 1.39 safety factor is that it is the reciprocal of the 0.72 design factor in Sec. 195.106. The 0.72 design factor was intended to account for material uncertainties and allowable defects in the construction of a pipeline, including defects allowed by API 5L.[61]

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[57] *See e.g.,* Ahmed Sellami ET AL., *Strain-Based Modeling of Burst Pressure in Pipelines with Selective Seam Weld Corrosion*, 217 Int'l J. of Pressure Vessels and Piping (2025); Raymond R. Fessler ET AL., *Predicting the Failure Pressure of SCC Flaws in Gas Transmission Pipelines, in* 2 PROC. OF THE 2012 9TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT 653 (2012).

[58] *See e.g.,* Andrew Cosham ET AL., *Crack-Like Defects in Pipelines: The Relevance of Pipeline-Specific Methods and Standards, in* 2 PROC. OF THE 2012 9TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT 713 (2012); Samarth Tandon ET AL., *Evaluation of Existing Fracture Mechanics Models for Burst Pressure Predictions, Theoretical and Experimental Aspects*, *in* 2 PROC. OF THE 2014 10TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT (2014).

[59] *See* Cara Macrory, Pipeline Rsch. Council Int'l, *Considerations for Crack ILI Response in Hazardous Liquids Pipelines* (2022).

[60] Am. Petroleum Inst., Recommended Practice 1176: Assessment and Management of Cracking in Pipelines, (1st ed. 2016) The second edition of API RP 1176 is expected in late 2025 or early 2026.

[61] API 5L is also incorporated by reference into Part 195. 49 CFR § 195.3(b)(12).

However, when operators perform failure pressure calculations, there is an implicit requirement to consider defect sizes and uncertainties within those evaluations, so the combination of a 1.39 safety factor with this more detailed assessment is unnecessary and duplicative. The change from this unnecessarily conservative approach to a more reasonable 1.25 safety factor is also supported in modern industry standards. For example, the ASME B31.G failure pressure calculation method for corrosion was updated in 2012 to allow a safety factor of 1.25. The use of a 1.25 safety factor for metal loss anomalies is also consistent with API RP 1160.

The Associations' proposed revisions to the response criteria for corrosion based on failure pressure calculations are also appropriate because they would reduce unnecessary excavation and repair activities. Reducing unnecessary projects not only conserves resources but it also reduces the risk of human error involved in any project, thereby reducing worker and public safety risks.

In addition, many pipelines have undergone multiple ILI runs that have provided a large amount of data and information on pipeline condition allowing for estimations of corrosion growth rates. Given this understanding it is unlikely that a general corrosion condition on a pipeline with a safety factor of above 1.25 will pose a threat to the integrity of a pipeline within a one-year timeframe of discovery. Moreover, for anomalies with burst pressures above 1.25x MOP, operators remain subject to the IM repair catch-all requirement[62] to schedule repairs if necessary based on an integrity assessment under Sec. 195.452(j) or an information analysis under Sec. 195.452(g). Thus, if other information about the risk of a particular anomaly indicates the need to repair that anomaly then it must be scheduled for repair.

In addition to the 1.25 safety factor, the Associations also propose revisions to repair criteria related to longitudinal seam weld corrosion. The current response criterion in Sec. 195.452(h)(4)(iii)(H) requires repair of "corrosion of or along a longitudinal seam weld," which has been interpreted by PHMSA[63] to require repair of any corrosion anomaly that intersects or is close to a longitudinal seam weld. However, industry experience indicates that most corrosion on or near the longitudinal seam does not represent a threat to pipeline integrity. This has resulted in thousands of unwarranted anomaly repair excavations, resulting in millions of dollars of repair costs that provide little safety benefit. PHMSA has recognized this issue in recent changes to the repair criteria for gas transmission lines.[64] The Association's proposed amendments mirror the Part 192 revisions and define the relevant corrosion as metal loss that may be "preferentially affecting a longitudinal seam." This change would ensure that resources are focused on conditions that represent a threat

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[62] 49 C.F.R. § 195.452(h)(1).

[63] Letter of Interpretation from John A. Gale, Director of Office Standards and Rulemaking, PHMSA, to Mr. Wm. Dean Gore, Jr., Vice President, Environmental & Regulatory Compliance, Plains All American GP LLC, PI-17-0014 (Apr. 26, 2018), https://www.phmsa.dot.gov/regulations/title49/interp/pi-17-0014.

[64] For the amendments to the gas repair criteria, PHMSA noted that "[c]orrosion that 'preferentially' affects the long seam is corrosion that is of and along the weld seam that is classified as selective seam weld corrosion." Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, 87 Fed. Reg. 52,224, 52,250 (Aug. 24, 2022).

to pipeline integrity. The proposed changes also reflect the language that is currently applicable to gas pipelines in Sec. 192.714 and Sec. 192.933.[65]

Repair Criteria for Cracks

The Associations propose revisions to Sec. 195.452(h)(4) repair criteria to include more specific crack response criteria for immediate repair conditions and 1-year crack response criteria for less severe cracks, based on failure pressure ratio calculations. Technology and engineering methods related to crack threats have advanced significantly since the original promulgation of the IM rules, and the Associations' proposed repair criteria for cracks capture those advancements, including two new immediate repair conditions for crack anomalies detected by ILI.

The Associations propose the use of a 1.25 safety factor for crack anomalies that qualify as one-year conditions. A 1.25 safety factor is well supported by industry research, experience and technical resources like API RP 1176 and TR 1190.[66] Specifically, TR 1190 demonstrates that there is little safety benefit in moving from a safety factor of 1.25 to 1.39.[67] Both of these standards informed the Association's proposed repair criteria for cracking threats.

Operator data and evidence-based industry research has found the repair criteria outlined in API TR 1190 to provide sufficient safeguards to protect the public. The criteria in TR 1190 are consistent with key elements of Part 195 Subparts E and F, Part 192 response criteria, API RP 1160, API RP 1176, CSA Z662, ASME B31.4, and STP-PT-011. A PRCI project[68] derived the optimal crack ILI response criteria for hazardous liquid pipelines, and the findings from this work formed the basis of API TR 1190 and elements of the pending release of API RP 1176, 2nd edition. Basing the IM cracking repair criteria on these criteria will set uniform standards, improve efficiency and help protect the public and the environment.

Repair Criteria for Dents and Dents with Metal Loss

The Associations propose new dent repair criteria which include immediate and 1-year conditions based on significant advancements in the understanding of dents. The immediate repair conditions target features that represent higher likelihoods of being injurious, or which may be related to severe mechanical damage. The 1-year conditions include dents that show industry-recognized risk factors that should be investigated, but which do not present an immediate safety threat. In addition, the Associations propose an alternate criterion that involves performing an ECA to

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65 49 C.F.R. § 192.714(d)(2)(vi), (d)(3)(v); 49 C.F.R. § 192.933(d)(2)(v), (d)(3)(v).

66 Am. Petroleum Inst., Recommended Practice 1176: Assessment and Management of Cracking in Pipelines, (1st ed. 2016); Am. Petroleum Inst., Technical Report 1190: Crack ILI Response: Maximum Depth and Failure Pressure Ratio, (1st ed. 2024).

67 Am. Petroleum Inst., Technical Report 1190: Crack ILI Response: Maximum Depth and Failure Pressure Ratio at 3, (1st ed. 2024).

68 *See* Cara Macrory, Pipeline Rsch. Council Int'l, *Considerations for Crack ILI Response in Hazardous Liquids Pipelines* (2022).

determine if alternate repair timelines are appropriate for dents that otherwise fit into the new immediate and 1-year criteria.

The Associations propose this ECA alternative to the prescriptive repair criteria for dents because it is well understood that the specific shape of a dent and operating conditions affect its level of risk. Dent shape and operating conditions allow for a more accurate determination of risk than using just dent depth.

The introduction of the first edition of API RP 1183 in 2020 provided a holistic framework for the management of pipeline dents and was an important milestone for the industry. [69] A key part of pipeline dent management in API 1183 is the understanding that tiered ECAs (or fitness for service) are possible and may rely on multiple methods.

The Associations' proposed ECA language provides a framework that operators may use to supplement the proposed prescriptive dent repair criteria. Dent ECAs may require robust data integration and use safety factors to account for loading, model, measurement, and material uncertainties. These elements are included in the Associations' proposed ECA language and are built on integrity management principles in accepted industry standards, including ASME B31.8S[70] and API 1160.[71]

The ECA methods in API 1183 are based on decades of pipeline industry experience and show that ECA processes for a dent should consider two types of assessments, fatigue and strain-based evaluations.

- Strain-based evaluations are recognized by the industry and have appeared in ASME B31.8 for over two decades (non-mandatory appendix R of ASME B31.8 and in CSA-Z662). Strain-based methods have continued to evolve and there has been significant work in this area in recent years to account for more parameters and uncertainties.[72] Strain-based evaluations are a key part of dent assessments.

- Fatigue based evaluations are a key part of dent assessments and industry papers and projects have developed technical methods and validation for many of the commonly used fatigue-based methods. Notably, PRCI reports show the amount of work that went into development of just one of the methods presented in API RP 1183.[73] Additionally, validation work using full scale fatigue testing of field dents presented in additional PRCI

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[69] Am. Petroleum Inst., Recommended Practice 1183: Assessment and Management of Pipeline Dents (1st ed. 2020).

[70] The Am. Soc'y of Mech. Eng'r, B31.8S - Managing System Integrity of Gas Pipelines, (2022).

[71] Am. Petroleum Inst., Recommended Practice 1160, Managing System Integrity for Hazardous Liquid Pipelines (3rd ed. 2019, reaffirmed 2024)

[72] *See* Arnav Rana ET AL., Pipeline Rsch. Council Int'l, *Improve Dent-Cracking Assessment Methods* (2022).

[73] *See* Sanjay Tiku ET AL., Pipeline Rsch. Council Int'l, *Fatigue Life Assessment of Dents with and without Interacting Features*.

research exemplifies how these methods are being validated and improved through organizations like PRCI.[74] Many other individual papers have been published with respect to other fatigue methods.[75] Ultimately, fatigue-based evaluations are a key part of dent assessments.

The presence of interacting features (e.g., metal loss, gouges, cracks etc.) may impact the results of the strain and fatigue assessments of dents. Operators have also investigated the ability of ILI to provide information about interacting threats via large PRCI projects.[76] Key findings from these projects show that the uncertainties in measurement (POD and sizing) are generally on the same order as what is accepted for stand-alone features such as metal loss or cracks. The presence and integrity impact of these features can be accounted for in assessments. Additionally, advancements in ILI technology and analysis have made it possible to identify gouging and mechanical damage related metal loss during inspections.[77] Operators also have access to multiple inline inspection data sets, right-of-way surveillance, and depth cover information that can be used for robust data integration to identify mechanical damage features.

Cost Justification

By targeting excavations where repair is needed, the Association expect that there will be a reduction in the number of digs performed to fix non-injurious anomalies – focusing resources on risk and rechanneling remaining resources to other actions that have an improved safety benefit.

Cracks

The Associations will provide cost information regarding anticipated cost savings for its proposed crack criteria updates in a subsequent filing.

Corrosion

The Associations' proposed changes to the corrosion repair criteria are expected to result in significant cost savings associated with avoiding excavations and repairs that are not necessary for safety. To provide a specific example, ILI technologies have improved substantially and can now

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[74] *See* PRCI MD-4-15, Performance of Dent Fatigue Models for Natural Dents Removed from Service.

[75] *See* R. L. Dotson ET AL., *Combining High Resolution In-Line Geometry Tools and Finite Element Analysis to Improve Dent Assessments*, *in* PROC. OF THE PIPELINE PIGGING AND INTEGRITY MANAGEMENT CONFERENCE, (2014).

[76] *See* Arnav Rana & Sanjay Tiku, Pipeline Rsch. Council Int'l, Verification of Screening Tools for Classifying ILI Reported Dents with Metal Loss Features (2023); Sanjay Tiku, Pipeline Rsch. Council Int'l, *Performance Evaluation of ILI Systems for Dents and Coincident Features* (2024), https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=20257&s=5B6EAFBE26AB49FA93493ACD715FF3AE&c=1.

[77] Matt Romney, Dane Burden & Mike Kirkwood, *The Power to Know More About Third Party Gouging, in* PROC. OF THE PIPELINE TECHNOLOGY CONF. (2022).

provide data that allows operators to differentiate corrosion intersecting a longitudinal seam (which is often not a threat to integrity) versus metal loss that is preferentially affecting the longitudinal seam.

The Associations sought information from their members on excavations to comply with the current criteria for corrosion. In a useful example of criteria that do not drive safety improvement, two operators provided information on 2700 digs conducted pursuant to the long-seam corrosion criteria at Sec. 195.452(h)(4)(iii)(H) on two different pipeline systems totaling 6000 anomalies investigated. The results of these investigations found incidental corrosion features crossing or near the long seam weld but showed no evidence of preferential attack of the long seam weld. This effort resulted in an estimated **$135MM** spent with very little improvement in pipeline safety.

Dents

The Associations' proposed dent criteria would reduce costs by eliminating unnecessary excavations driven by the current, arbitrary dent depth criteria. The Associations propose to keep the depth-based criteria for dents but also allow operators the option apply modern ECA methods to determine if dents are a threat to pipeline integrity. One operator informed the Associations it would save **$1+ million annually** if it were permitted to use the Association's proposed dent criteria.

d. Discovery of Conditions

Question – Section III.A.4

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.

<u>Comments:</u>

The Associations do not have any substantive comments on the existing regulations for discovery of conditions.

e. Integrity Management Interpretations and Other Guidance

Question – Section 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)) that 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.

<u>Comments:</u>

As a general matter, the Associations observe that PHMSA has in the past relied on interpretation letters and other informal agency guidance documents as support for its positions during inspections and in the context of enforcement cases. As provided in relevant case law[78] and noted in recent DOT guidance, informal agency guidance documents do not have the force of law and cannot be relied on to demonstrate a violation of the pipeline safety regulations.[79] The Associations welcome agency guidance as a means for understanding the regulations, and at the same time agree with recent DOT guidance that it cannot serve as the basis for enforcement because it lacks the force of law.

Regarding PHMSA interpretations that impose unjustified compliance costs, the Associations request that PHMSA rescind a 2018 interpretation issued to Plains All American GP LLC regarding long seam weld corrosion.[80] The Plains interpretation concerned the IM 180-day repair criteria for corrosion of or along a longitudinal seam weld, and took the position that any corrosion, preferential or otherwise, must be actioned under this repair criteria. As also discussed in the Associations' response to questions III.A.1 and III.B.5, this repair criteria is overly broad and does not differentiate between preferential seam corrosion and general corrosion. While preferential

[78] *See, e.g., Chrysler Corporation v. Brown,* 441 U.S. 281, 301-303 (1979); *Appalachian Power Co. v. E.P.A.,* 208 F.3d 1015, 1020 (D.C. Cir. 2000).

[79] Memorandum Regarding Procedural Requirements for DOT Enforcement Actions from the U.S. Dept' of Transportation, Office of the General Counsel, to Secretarial Officers and Heads of Operating Administrators at 8 (Mar. 11, 2025), https://www.transportation.gov/administrations/office-general-counsel/general-counsel's-enforcement-memorandum; *see also In the Matter of Oasis Midstream Partners,* CPF No. 3-2019-5020, Final Order at 9 (Aug. 19, 2020).

[80] Letter of Interpretation from John A. Gale, Director of Office Standards and Rulemaking, PHMSA, to Mr. Wm. Dean Gore, Jr., Vice President, Environmental & Regulatory Compliance, Plains All American GP LLC, PI-17-0014 (Apr. 26, 2018), https://www.phmsa.dot.gov/regulations/title49/interp/pi-17-0014.

seam corrosion does warrant attention and is included in the Associations' proposed list of 1-year conditions, general corrosion that happens to be in proximity to the seam but which is otherwise not injurious should not require excavation and repair.[81]

PHMSA has recognized this difference in recent changes to the repair criteria for gas transmission lines.[82] In both the IM and non-IM repair criteria for gas pipelines, PHMSA modified the requirements for corrosion related to long seam welds by specifying that only preferential corrosion of the seam will trigger the repair criteria.[83] The Associations request that PHMSA also recognize that distinction in the liquid IM repair criteria.

Proposed Changes to Part 195

195.452(h)(4)(ii)(I)

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(I) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0

Note: This updated criteria for seam metal loss is within the Associations' proposed set of new 1-year repair criteria. This proposal is part of the Associations' larger proposal to amend 195.452(h), set out in full in response to question III.A.1.

Technical, Safety, and Economic Justification for Proposed Changes:

The Associations sought information from their members on excavations to comply with the current Sec. 195.452(h) IM repair criteria for corrosion. In a useful example of criteria that do not drive safety improvement, two operators provided information on approximately 2700 digs conducted pursuant to the long-seam corrosion criteria at Sec. 195.452(h)(4)(iii)(H) on two different pipeline systems totaling approximately 6000 anomalies investigated. The results of these investigations found incidental corrosion features crossing or near the long seam weld but showed no evidence of preferential attack of the long seam weld. This effort resulted in an estimated **$135MM** spent with very little improvement in pipeline safety.

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[81] *See* Michael Turnquist, Pipeline Rsch. Council Int'l, *Response to Corrosion Intersecting the Longitudinal Seam in Liquid Pipes* (2024).

[82] For the amendments to the gas repair criteria, PHMSA noted that "[c]orrosion that 'preferentially' affects the long seam is corrosion that is of and along the weld seam that is classified as selective seam weld corrosion." Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, 87 Fed. Reg. 52,224, 52,250 (Aug. 24, 2022).

[83] 49 C.F.R. § 192.714(d)(2)(vi), (d)(3)(v); 49 C.F.R. § 192.933(d)(2)(v), (d)(3)(v).

f. Differences Between Facility Types

Question – Section III.A.6

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?

Comments:

The Associations believe that the current IM regulations already require operators to tailor their programs to the unique characteristics of their systems. The Associations do not see a need to change the current regulations on this topic.

The current regulations require risk analysis and other processes that account for difference in pipeline diameter, operating pressure, product type, pipeline material properties, geographic locations and surrounding receptors, and many other factors. These processes are the basis for how operators determine what actions may be needed to maintain the integrity of their assets. PHMSA has published a risk pipeline risk modeling overview[84] and the regulations include risk parameters to consider in developing an integrity management program.[85]

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[84] PHMSA, *Pipeline Risk Modeling: Overview of Methods and Tools for Improved Implementation* (Feb. 1, 2020), https://www.phmsa.dot.gov/pipeline/risk/modeling-work-group/pipeline-risk-modeling-overview-methods-and-tools-improved-implementation-report.

[85] 49 C.F.R. § 195.452, Appendix C.

g. *Repair Types*

Question – Section 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:

Sec. 195.402 requires operators to develop operations and maintenance manuals that include procedures for pipeline repair, including criteria for determining when a repair is needed and how to perform a repair. There are several industry reference documents and consensus standards, including ASME B31.4-2006, table 451.6.2.9-1, that address the issue of temporary vs. permanent repairs for the full range of anomalies. Operators develop processes that assess whether a repair is considered permanent vs. temporary. A temporary repair is a repair that will be re-evaluated within a period specified by the pipeline operator's written procedures. The anticipated life of a repair depends on many circumstances and should include consideration of risk. Therefore, the determination of permanent and temporary is left to the individual pipeline operator.

Pipeline operators must prepare and follow written procedures for making any repair, whether temporary or permanent. PHMSA has issued guidance on temporary and permanent repairs[86] and ASME B31.4-2006, table 451.6.2.9-1 provides examples of permanent repair methods to address defects in liquid pipelines. In the event the time to failure is estimated to occur before it is feasible to make a permanent repair at the time of anomaly discovery, methods documented in operations and maintenance procedures and proven by test, investigation, or experience that are outside of the examples listed in ASME B31.4-2006, table 451.6.2.9-1, may be used and considered a temporary repair.

Other industry documents and standards also address pipeline repair, for example PRCI's Pipeline Repair Manual.[87] These materials include guidance on conditions that may require a temporary as

[86] PHMSA, Temporary Repair and Permanent Repair Frequently Asked Questions (Nov. 2, 2022), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-11/PHMSA%20Temporary-Permanent%20Repair%20FAQs.pdf.

[87] Bill Bruce, Pipeline Rsch. Council Int'l, *PRCI Pipeline Repair Manual 2021 Edition* (2022).

opposed to a permanent repair. These materials also address methods for assessment of the temporary repair until a permanent repair can be completed.

As a practical matter, liquid pipeline operating companies rarely perform temporary repairs. Most temporary repairs are used to manage anomalies that require short-term mitigation or when permanent repair is not immediately feasible. For example, repairs of conditions where restrictions on accessing the anomaly or unique locations of the anomaly. Challenging conditions include repairs on fittings, pipe bends, and conditions that make installation of a Type B sleeve or cut-out and replacement of pipe challenging and require additional time for planning the permanent repair. Operators generally manage temporary to permanent repair conversions when other scheduled maintenance activity is planned within the same area or facility, as these conversions can be a significant effort for pipeline operators to undertake and often require shutdown of portions of the pipeline system. Many of the temporary repairs completed are located on facility piping or appurtenances at facilities or are used to address small leaks in liquid pipelines pending a permanent repair solution (e.g., future cut-out).

With regard to average costs associated with repair methods, there is no fixed price for any repair method. Repair costs are highly variable and depend on several factors. Excavation costs vary by region—ranging from around $40,000 in remote areas of Texas to up to $1 million or more in challenging locations such as lakes, swamps, highways, or highly populated areas. Additional costs also need to be considered, such as pressure reductions and business disruptions that can be up to several million dollars per day. Labor costs associated with repairs also vary widely depending on the effort required to remove coating, locate the defect, prepare the area, install the repair material (such as welding), and recoat. If a cut-out is required, further expenses may be incurred to drain the line or install a stopple.

h. Impact on Small Entities

Question – Section III.A.8

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?

Comments:

The liquid transmission and gathering segments of the energy supply chain are extremely diverse, with companies of various sizes. For smaller companies, especially those operating gathering lines, regulations should be designed to consider available resources. Smaller gathering line companies generally do not have extensive in-house regulatory, engineering, and compliance resources, and often rely on third-party contractors for specialized services. For illustration, one of the Associations, GPA Midstream, has 50 members that operate gathering facilities. Seven members operate their gathering assets with around 25 total employees or less, and about 14 members operate with between 50 and 100 employees. Due to the need for outside expertise and lack of economies of scale, these smaller operators often face higher per-mile compliance costs. Smaller staffing levels also make tight compliance timeframes challenging. Additionally, there may be a lack of available resources, as operators compete to hire a limited number of third-party experts, which could delay compliance and increase costs.

The Associations support the current IM paradigm that exempts most gathering lines due to their operational parameters and relatively low risk profiles. The current requirements allow gathering line operators to adopt flexible and risk-based programs to safely manage their systems. Additionally, PHMSA must ensure rules are cost beneficial and protect small businesses as required by the Regulatory Flexibility Act[88] and consider the effect of any proposed rule on small businesses in the risk assessment as required by the Pipeline Safety Act.[89] Scrutinizing the cost impact on small businesses and balancing costs with benefits will ensure smaller operators are not burdened unnecessarily. Lastly, PHMSA should have appropriate representation during the meetings of its technical safety committees, the Technical Pipeline Safety Standards Committee (Gas Pipeline Advisory Committee) for natural gas pipelines, and the Technical Hazardous Liquid Pipeline Safety Standards Committee (Liquids Pipeline Advisory Committee) for hazardous liquid pipelines.[90] If PHMSA proposes regulatory changes for gathering lines, the Committees should reflect expertise from that sector. If regulatory changes are proposed for carbon dioxide lines, then expertise from that sector should be a part of the discussion.

i. Reporting Requirements

Question – Section 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?

[88] 5 U.S.C. §§ 603, 604.

[89] 49 U.S.C. § 60102(b)(3).

[90] 49 U.S.C. § 60115(b).

Comments:

The Associations intend to comment on the reporting issues described in this question, among other reporting topics, in PHMSA's Regulatory Review ANPRM.[91]

j. Statutory Alignment

> **Question – Section 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:

The Associations believe that the current non-IM anomaly remediation criteria in Sec. 195.401(b)(3) are appropriate.

k. Non-HCA Pipeline Facilities

> **Question – Section III.B.1**
>
> How do operators of different categories of hazardous liquid or carbon dioxide pipelines approach the discovery, evaluation, and remediation of anomalies on non-HCA segments in complying with repair requirements at § 195.401? Which elements, if any, do operators apply from the IM response criteria and remediation timelines at § 195.452(h) for anomalies discovered on non-HCA segments? Please describe typical costs associated with discovery, evaluation, and remediation of anomalies on non-HCA segments, with as much specificity by anomaly type as possible.

Comments:

The Associations believe that the current repair requirements for liquids pipelines in non-HCA areas are appropriate. Operators often apply similar tools and methods used under the IM program to non-HCA areas. Appropriately, operators may use different response timelines and priorities in non-HCA versus HCA areas, with the emphasis on risk. While repair costs are generally the same as in HCA areas, business disruption and excavation costs are generally lower in non-HCA segments.

The Associations do not propose any changes to the non-HCA requirements for discovery, evaluation and remediation set out in Sec. 195.401 and Sec. 195.416.

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[91] Pipeline Safety: Mandatory Regulatory Reviews to Unleash American Energy and Improve Government Efficiency, 90 Fed. Reg. 23,660 (proposed Jun. 4, 2025).

l. Alternatives or Supplements to Hazardous Liquids Repair Criteria and Remediation Timelines

Question – Section III.B.2
Are there alternatives or supplements to the anomaly repair criteria and remediation timelines that should be incorporated into PHMSA's IM regulations? Are there particular anomaly types whose risks justify existing repair criteria and remediation timelines, or even broader repair criteria and more aggressive timelines than specified in PHMSA regulations? Conversely, are there anomalies identified in PHMSA regulations whose lower risks justify different repair criteria or longer remediation timelines than specified in the regulations? Please identify any specific regulatory amendments that merit consideration, as well as the technical, safety, and economic reasons supporting those recommended amendments.

Comments:

The Associations propose changes to the anomaly repair criteria in Sec. 195.452(h), as set out in detail in the response to ANPRM Section III.A.1. These updates reflect the fact that there are anomaly types whose risk continues to justify existing, immediate repair criteria and timelines. In addition, the Associations have proposed adding certain cracking anomalies to the list of immediate repair conditions, based on the modern understanding of cracking threats from improved ILI technologies and methods of defect analysis. At the same time, there are other kinds of anomalies where the data and experience show that immediate, 60-day or 180-day repairs are not required, and a 1-year condition is appropriate. Finally, the Associations also propose criteria for more detailed evaluation of defects to determine if they need repair or can safely be monitored over time. The Associations provided detailed comments on the topic of repair criteria in response to ANPRM Question III.A.1, above. Relevant portions of that content are repeated below.

New Immediate Conditions

The Associations propose specific repair criteria for crack defects that reflect modern technology and engineering analysis. These include two new immediate repair conditions for crack-like indications based on ILI data with depth greater than 70% of nominal wall thickness or with depth that exceeds the maximum depth sizing capabilities of the ILI tool, and crack-like indications where a calculation of the remaining strength of the pipe less than 1.10 times the established maximum operating pressure at the location of the anomaly. This approach to crack defects aligns with operator data and evidence-based industry research as outlined in API TR 1190.

One Year Conditions

The Associations request that PHMSA create a new 1-year repair condition that combines and updates the current 60-day and 180-day repair conditions. This change would recognize that advanced assessment tools and operator experience with anomaly investigation and repair have shown that many types of defects can be safely scheduled for repair on a 1-year basis. A 1-year repair deadline for these defects also allows operators more time to plan for such repairs, obtain permits and arrange and optimize necessary resources. Replacing 60-day and 180-day repair conditions with one-year conditions also better aligns the Part 195 requirements with Part 192, where PHMSA already provides for one-year conditions.[92]

Extended Schedule Conditions

The Associations propose that PHMSA allow operators to establish extended schedule conditions, where engineering analysis demonstrates it is appropriate to do so. The analysis required for establishing extended schedule conditions draws from modern industry standards for the management of metal loss, cracks, and dents. The Associations' proposal would allow operators to use ECA to schedule dent repairs, as the Part 192 regulations allow for gas transmission pipelines.

Proposed Changes to Part 195:

Sec. 195.452(h)

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(4) ***~~Special r~~Requirements for scheduling remediation*** —

(i) ***Immediate repair conditions.*** An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce the operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure ~~using the formulas referenced in paragraph (h)(4)(i)(B)~~ pursuant to paragraph (h)(1)(i) of this section. If no suitable remaining strength calculation method can be identified, an operator must lower its operating pressure to 40% SMYS or implement a ~~minimum~~ 20% ~~percent or greater~~ operating pressure reduction, based on ~~actual~~ the highest operating pressure for two months prior to the date of inspection, until the anomaly is repaired. An operator must treat the following conditions as immediate repair conditions:

(A) Metal loss with depth greater than 80% of nominal wall thickness ~~regardless of dimensions~~.

(B) ~~A~~ Metal loss where a calculation of the remaining strength of the pipe in accordance with paragraph (h)(1)(i) of this section shows a predicted failure pressure less than the established maximum operating pressure at the location of the anomaly. ~~Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (incorporated by reference, see § 195.3) and PRCI PR-3-805 (R-STRENG) (incorporated by reference, *see* § 195.3).~~

[92] 49 C.F.R. § 192.933(d)(2).

(C) Crack-like indication based on ILI data with depth greater than 70% of nominal wall thickness or with depth that exceeds the maximum depth sizing capabilities of the ILI tool.

(D) Crack-like indication where a calculation of the remaining strength of the pipe in accordance with paragraph (h)(1)(i) of this section shows a predicted failure pressure less than 1.10 times the established maximum operating pressure at the location of the anomaly.

(~~C~~E) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of ~~metal loss, cracking, or a stress riser~~ cracking, gouging, or metal loss that is determined by the operator to likely be caused by mechanical damage, unless an extended schedule is established in accordance with paragraph 195.452(h)(4)(iii) of this section.

(~~D~~F) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter, unless an extended schedule is established in accordance with paragraph 195.452(h)(4)(iii) of this section.

(~~E~~G) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

~~(ii) ***60-day conditions.*** Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 60 days of discovery of condition.~~

(ii) ***1 year conditions.*** Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 1 year of discovery of condition, unless an extended schedule is established in accordance with paragraph (h)(4)(iii) of this section:

(A) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than ~~3~~2% of the pipeline nominal diameter or ~~(~~greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12~~)~~.

(B) A dent located on the bottom of the pipeline that has any indication of ~~metal loss, cracking, or a stress riser~~ cracking, gouging, or metal loss that is determined by an operator to be caused by mechanical damage.

~~(iii) ***180-day conditions.*** Except for conditions listed in paragraph (h)(4)(i) or (ii) of this section, an operator must schedule evaluation and remediation of the following within 180 days of discovery of the condition:~~

(~~A~~C) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

~~(B) A dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).~~

(~~C~~D) A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.

(E) A dent located anywhere on the pipe with metal loss >20% in depth that is determined by the operator to be caused by corrosion and is not the result of mechanical damage to the pipeline.

(~~D~~F) A calculation of the remaining strength of the pipe in accordance with paragraph (h)(1)(i) of this section that ~~shows an operating pressure~~ has a predicted failure pressure that is less than 1.25 times the current established maximum operating pressure at the location of the anomaly. ~~Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G and PRCI PR-3-805 (R-STRENG).~~

(~~E~~G) An area of general corrosion that has a predicted failure pressure of less than 1.25 times the MOP.~~with a predicted metal loss greater than 50% of nominal wall~~.

~~(F) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.~~

~~(G) A potential crack indication that when excavated is determined to be a crack.~~

~~(H) Corrosion of or along a longitudinal seam weld.~~

(H) Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure of less than 1.25 times the MOP.

(I) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0.

(~~I~~J) A gouge ~~or groove~~ greater than 12.5% of nominal wall thickness.

(iii) ***Extended Schedule Conditions.*** To establish an extended schedule, an operator must:

(A) Conduct a time-dependent assessment for corrosion and crack features that, when considering growth mechanism and ILI depth tolerance, determines when a potential corrosion and/or crack anomaly reaches either:

1. 80% of nominal wall thickness; or,

2. A calculation of the remaining strength of the pipe in accordance with paragraph (h)(1)(i) of this section shows a predicted failure pressure of 1.10 times the established maximum operating pressure at the location of the anomaly.

(B) Conduct an Engineering Critical Assessment (ECA) for dents that considers:

1. The size, location, and when appropriate, the shape of the dent.

2. 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. A review of metal loss, 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 prior inline inspections.

4. 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. An evaluation of 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 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. 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.

Technical, Safety, and Economic Justification for Proposed Changes:

Technical and Safety Justification

The current repair criteria in Sec. 195.452(h) are not based on modern engineering tools and practices and do not reflect the knowledge gained through 25 years of implementing IM programs, including lessons learned from operator excavations and maintenance inspections. PHMSA's past lack of responsiveness to industry advancements in IM practices since the original IM rulemaking has created significant inefficiency in the repair process, inhibited innovation, and been a barrier to improved risk management practices. Data and evidence-based industry research has established advanced approaches and technologies for defect detection, characterization, scheduling and repair. These approaches are captured in numerous industry consensus standards and technical publications and are cited throughout these comments. Elements of many of these technical standards, including API RP 1160, API RP 1176, and API RP 1183 informed several of the Associations' proposed changes to Sec. 195.452(h). If adopted, these changes would allow operators to better predict anomaly failure pressures, more accurately estimate degradation rates, and perform engineering critical assessments (ECAs), significantly improving pipeline safety.

Repair-criteria specific justifications are summarized below:

Failure Pressure Calculation Methods

Since the adoption of the IM regulations in 2000, technical experts have developed several new analytical methods to more accurately determine failure pressure of corrosion and cracking anomalies. To bring in these advancements, the Associations propose amending the regulations to add Sec. 195.452(h)(1)(i) to include a non-exclusive list of additional failure pressure calculation methods. These methods would address a wider variety of feature types, beyond corrosion and the B31G and R-Streng methods.

The current IM regulations prevent the use of modern methods for calculating the remaining strength of certain types of defects. Specifically, in Sec. 195.452(h)(4)(i)(B) and Sec. 195.452(h)(4)(iii)(D), there are only two remaining strength calculation methods listed and both are limited to corrosion. While the regulations provide that other methods may be used, expanding the list to include other acceptable methods for a wider variety of feature types provides regulatory certainty for operators that additional methods are allowed.

Additional methods that operators could use include, but is not limited to the following:

- **PSqr**: This method is used for metal loss anomalies. The PSqr methodology estimates the remaining strength of corroded pipelines by calculating the pressure at which failure is predicted, using a squared pressure ratio (P^2) approach that incorporates defect geometry, material properties, and safety factors to ensure structural integrity.[93] Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[94]

- **API 579-1/ASME FFS-1**: This method is used for assessing metal loss, cracks and crack-like anomalies. API 579, Part 9 (Assessment of Crack-Flaws) provides three assessment levels and employs a Failure Assessment Diagram (FAD) approach to account for failure by fracture and by plastic collapse. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[95]

- **PRCI MAT-8**: This method is used for blunt flaws, cracks and crack-like anomalies. The Materials Assessment Tool - Version 8 (MAT-8) also employs a FAD approach. It has been recently updated to include probabilistic analysis and is under review for inclusion in API 579-1/ASME FFS-1. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[96]

- **CorLAS:** CorLAS (Corrosion Life Assessment Software) was developed for the assessment of sharp, longitudinally orientated surface flaws in a cylinder subject to internal pressure (i.e. axial cracks). It includes empirical correlations between the J-integral and the yield and tensile strength and Charpy V-notch impact energy) derived from tests on pipeline steels. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[97]

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[93] *See e.g.,* Mohammad Al-Amin ET AL., *Achieving Consistent Safety by Using Appropriate Safety Factors in Corrosion Management Program*, *in* 1 PROC. OF THE 2020 13TH INT'L PIPELINE CONF., PIPELINE AND FACILITIES INTEGRITY (2020).

[94] *See e.g.,* Shahani Kariyawasam, Shenwei Zhang, Jason Yan, Terry Huang, Mohammad Al-Amin, & Erwin Gamboa, Plausible Profiles (Psqr) corrosion assessment model (2020).

[95] *See e.g.,* Andrew Cosham & Phil Hopkins, *The Pipeline Defect Assessment Manual, in* PROC. OF THE 2002 4TH INT'L PIPELINE CONF., 1565 (2002); Ted L. Anderson & David A. Osage, Am. Petroleum Inst., *API 579: A comprehensive fitness-for-service guide*, *in* 77 Int'l J. of Pressure Vessels and Piping, 953 (2000).

[96] *See e.g.,* Ted L. Anderson, Pipeline Rsch. Council Int'l, *Assessing Crack-Like Flaws in Longitudinal Seam Weld: A State-of-the-Art Review* (2017); Thomas Dessein ET AL., *Burst Pressure Prediction for Axial Cracks in Pipelines With Non-Ideal Depth Profiles, in* 2B PROC. OF THE 2024 15TH INT'L PIPELINE CONF., PIPELINE AND FACILITIES INTEGRITY (2024).

[97] *See e.g.,* Ahmed Sellami ET AL., Strain-Based Modeling of Burst Pressure in Pipelines with Selective Seam Weld Corrosion, 217 Int'l J. of Pressure Vessels and Piping (2025); Raymond R. Fessler ET AL., *Predicting the Failure Pressure of SCC Flaws in Gas Transmission Pipelines, in* 2 PROC. OF THE 2012 9TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT 653 (2012).

- **Batelle NG-18 Ln-Sec and Modified Ln-Sec**: This method is used for axially oriented surface anomalies. NG-18 is a semi-empirical model for predicting the failure stress of a pressurized cylinder with a longitudinal crack like defect. Industry experience with this method demonstrates that it may not be appropriate for all circumstances, particularly for pipe seams with a seam joint factor less than 1 that operates in the brittle regime, but may be used for pipelines operating within the ductile regime.[98]

The Associations have also proposed added safety margins of 1.25x MOP when conducting remaining strength calculations under certain proposed 1-year conditions. The Associations based this safety margin on PRCI research[99] and expected changes to RP 1176.[100]

Repair Criteria for Corrosion

The Associations propose updates to Sec. 195.452(h) repair criteria for corrosion features to focus those criteria on risk. First, the Associations propose a 1.25 safety factor rather than a factor of 1.39 for metal loss anomalies that qualify as 1-year conditions. The original rationale for a 1.39 safety factor is that it is the reciprocal of the 0.72 design factor in Sec. 195.106. The 0.72 design factor was intended to account for material uncertainties and allowable defects in the construction of a pipeline, including defects allowed by API 5L.[101]

However, when operators perform failure pressure calculations, there is an implicit requirement to consider defect sizes and uncertainties within those evaluations, so the combination of a 1.39 safety factor with this more detailed assessment is unnecessary and duplicative. The change from this unnecessarily conservative approach to a more reasonable 1.25 safety factor is also supported in modern industry standards. For example, the ASME B31.G failure pressure calculation method for corrosion was updated in 2012 to allow a safety factor of 1.25. The use of a 1.25 safety factor for metal loss anomalies is also consistent with API RP 1160.

The Associations' proposed revisions to the response criteria for corrosion based on failure pressure calculations are also appropriate because they would reduce unnecessary excavation and repair activities. Reducing unnecessary projects not only conserves resources but it also reduces the risk of human error involved in any project, thereby reducing worker and public safety risks.

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[98] *See e.g.,* Andrew Cosham ET AL., *Crack-Like Defects in Pipelines: The Relevance of Pipeline-Specific Methods and Standards, in* 2 PROC. OF THE 2012 9TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT 713 (2012); Samarth Tandon ET AL., *Evaluation of Existing Fracture Mechanics Models for Burst Pressure Predictions, Theoretical and Experimental Aspects*, *in* 2 PROC. OF THE 2014 10TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT (2014).

[99] *See* Cara Macrory, Pipeline Rsch. Council Int'l, *Considerations for Crack ILI Response in Hazardous Liquids Pipelines* (2022).

[100] Am. Petroleum Inst., Recommended Practice 1176: Assessment and Management of Cracking in Pipelines, (1st ed. 2016) The second edition of API RP 1176 is expected in late 2025 or early 2026.

[101] API 5L is also incorporated by reference into Part 195. 49 CFR § 195.3(b)(12).

In addition, many pipelines have undergone multiple ILI runs that have provided a large amount of data and information on pipeline condition allowing for estimations of corrosion growth rates. Given this understanding it is unlikely that a general corrosion condition on a pipeline with a safety factor of above 1.25 will pose a threat to the integrity of a pipeline within a one-year timeframe of discovery. Moreover, for anomalies with burst pressures above 1.25x MOP, operators remain subject to the IM repair catch-all requirement[102] to schedule repairs as necessary based on an integrity assessment under Sec. 195.452(j) or an information analysis under Sec. 195.452(g). Thus, if other information about risk indicates the need to repair an anomaly then it must be scheduled for repair.

In addition to the 1.25 safety factor, the Associations also propose revisions to repair criteria related to longitudinal seam weld corrosion. The current response criterion in Sec. 195.452(h)(4)(iii)(H) requires repair of "corrosion of or along a longitudinal seam weld," which has been interpreted by PHMSA[103] to require repair of any corrosion anomaly that intersects or is close to a longitudinal seam weld. However, industry experience indicates that most corrosion on or near the longitudinal seam does not represent a threat to pipeline integrity. This has resulted in thousands of unwarranted anomaly repair excavations, resulting in millions of dollars of repair costs that provide little safety benefit. PHMSA has recognized this issue in recent changes to the repair criteria for gas transmission lines.[104] The Association's proposed amendments mirror the Part 192 revisions and define the relevant corrosion as metal loss that may be "preferentially affecting a longitudinal seam." This change would ensure that resources are focused on conditions that represent a threat to pipeline integrity. The proposed changes also reflect the language that is currently applicable to gas pipelines in 192.714 and 192.933.[105]

Repair Criteria for Cracks

The Associations propose revisions to Sec. 195.452(h)(4) repair criteria to include more specific crack response criteria for immediate repair conditions and 1-year crack response criteria for less severe cracks, based on failure pressure ratio calculations. Technology and engineering methods related to crack threats have advanced significantly since the original promulgation of the IM rules, and the Associations' proposed repair criteria for cracks capture those advancements, including two new immediate repair conditions for crack anomalies detected by ILI.

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102 49 C.F.R. § 195.452(h)(1).

103 Letter of Interpretation from John A. Gale, Director of Office Standards and Rulemaking, PHMSA, to Mr. Wm. Dean Gore, Jr., Vice President, Environmental & Regulatory Compliance, Plains All American GP LLC, PI-17-0014 (Apr. 26, 2018), https://www.phmsa.dot.gov/regulations/title49/interp/pi-17-0014.

104 For the amendments to the gas repair criteria, PHMSA noted that "[c]orrosion that 'preferentially' affects the long seam is corrosion that is of and along the weld seam that is classified as selective seam weld corrosion." Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, 87 Fed. Reg. 52,224, 52,250 (Aug. 24, 2022).

105 49 C.F.R. §§ 192.714(d)(2)(vi), 192.714(d)(3)(v), 192.933(d)(2)(v) & 192.933(d)(3)(v).

The Associations propose the use of a 1.25 safety factor for crack anomalies that qualify as one-year conditions. A 1.25 safety factor is well supported by industry research, experience and technical resources like API RP 1176 and TR 1190.[106] Specifically, TR 1190 demonstrates that there is little safety benefit in moving from a safety factor of 1.25 to 1.39.[107] Both of these standards informed the Association's proposed repair criteria for cracking threats.

Operator data and evidence-based industry research has found the repair criteria outlined in API TR 1190 to provide sufficient safeguards to protect the public. The criteria in TR 1190 are consistent with key elements of Part 195 Subparts E and F, Part 192 response criteria, API RP 1160, API RP 1176, CSA Z662, ASME B31.4, and STP-PT-011. A PRCI project[108] derived the optimal crack ILI response criteria for hazardous liquid pipelines, and the findings from this work formed the basis of API TR 1190 and elements of the pending release of API RP 1176, 2nd edition. Basing the IM cracking repair criteria on these criteria will set uniform standards, improve efficiency and help protect the public and the environment.

Repair Criteria for Dents and Dents with Metal Loss

The Associations propose new dent repair criteria which include immediate and 1-year conditions based on significant advancements in the understanding of dents. The immediate repair conditions target features that represent higher likelihoods of being injurious, or which may be related to severe mechanical damage. The 1-year conditions include dents that show industry-recognized risk factors that should be investigated, but which do not present an immediate safety threat. In addition, the Associations propose an alternate criterion that involves performing an ECA to determine if alternate repair timelines are appropriate for dents that otherwise fit into the new immediate and 1-year criteria.

The Associations propose this ECA alternative to the prescriptive repair criteria for dents because it is well understood that the specific shape of a dent and operating conditions affect its level of risk. Dent shape and operating conditions allow for a more accurate determination of risk than using just dent depth.

The introduction of the first edition of API RP 1183 in 2020 provided a holistic framework for the management of pipeline dents and was an important milestone for the industry. [109] A key part of

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[106] Am. Petroleum Inst., Recommended Practice 1176: Assessment and Management of Cracking in Pipelines, (1st ed. 2016); Am. Petroleum Inst., Technical Report 1190: Crack ILI Response: Maximum Depth and Failure Pressure Ratio, (1st ed. 2024).

[107] Am. Petroleum Inst., Technical Report 1190: Crack ILI Response: Maximum Depth and Failure Pressure Ratio at 3, (1st ed. 2024).

[108] *See* Cara Macrory, Pipeline Rsch. Council Int'l, *Considerations for Crack ILI Response in Hazardous Liquids Pipelines* (2022).

[109] Am. Petroleum Inst., Recommended Practice 1183: Assessment and Management of Pipeline Dents (1st ed. 2020).

pipeline dent management in API 1183 is the understanding that tiered ECAs (or fitness for service) are possible and may rely on multiple methods.

The Associations' proposed ECA language provides a framework that operators may use to supplement the proposed prescriptive dent repair criteria. Dent ECAs may require robust data integration and use safety factors to account for loading, model, measurement, and material uncertainties. These elements are included in the Associations' proposed ECA language and are built on integrity management principles in accepted industry standards, including ASME B31.8S[110] and API 1160.[111]

The ECA methods in API 1183 are based on decades of pipeline industry experience and show that ECA processes for a dent should consider two types of assessments, fatigue and strain-based evaluations.

- Strain-based evaluations are recognized by the industry and have appeared in ASME B31.8 for over two decades (non-mandatory appendix R of ASME B31.8 and in CSA-Z662). Strain-based methods have continued to evolve and there has been significant work in this area in recent years to account for more parameters and uncertainties.[112] Strain-based evaluations are a key part of dent assessments.

- Fatigue based evaluations are a key part of dent assessments and industry papers and projects have developed technical methods and validation for many of the commonly used fatigue-based methods. Notably, PRCI reports show the amount of work that went into development of just one of the methods presented in API RP 1183.[113] Additionally, validation work using full scale fatigue testing of field dents presented in additional PRCI research exemplifies how these methods are being validated and improved through organizations like PRCI.[114] Many other individual papers have been published with respect to other fatigue methods.[115] Ultimately, fatigue-based evaluations are a key part of dent assessments.

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[110] The Am. Soc'y of Mech. Eng'r, B31.8S - Managing System Integrity of Gas Pipelines, (2022).

[111] Am. Petroleum Inst., Recommended Practice 1160, Managing System Integrity for Hazardous Liquid Pipelines (3rd ed. 2019, reaffirmed 2024).

[112] *See* Arnav Rana ET AL., Pipeline Rsch. Council Int'l, *Improve Dent-Cracking Assessment Methods* (2022).

[113] *See* Sanjay Tiku ET AL., Pipeline Rsch. Council Int'l, *Fatigue Life Assessment of Dents with and without Interacting Features*.

[114] *See* PRCI MD-4-15, Performance of Dent Fatigue Models for Natural Dents Removed from Service.

[115] *See* R. L. Dotson ET AL., *Combining High Resolution In-Line Geometry Tools and Finite Element Analysis to Improve Dent Assessments*, *in* PROC. OF THE PIPELINE PIGGING AND INTEGRITY MANAGEMENT CONFERENCE, (2014).

The presence of interacting features (e.g., metal loss, gouges, cracks etc.) may impact the results of the strain and fatigue assessments of dents. Operators have also investigated the ability of ILI to provide information about interacting threats via large PRCI projects.[116] Key findings from these projects show that the uncertainties in measurement (POD and sizing) are generally on the same order as what is accepted for stand-alone features such as metal loss or cracks. The presence and integrity impact of these features can be accounted for in assessments. Additionally, advancements in ILI technology and analysis have made it possible to identify gouging and mechanical damage related metal loss during inspections.[117] Operators also have access to multiple inline inspection data sets, right-of-way surveillance, and depth cover information that can be used for robust data integration to identify mechanical damage features.

Cost Justification

By targeting excavations where repair is needed, the Association expect that there will be a reduction in the number of digs performed to fix non-injurious anomalies – focusing resources on risk and rechanneling remaining resources to other actions that have an improved safety benefit.

Cracks

The Associations will provide cost information regarding anticipated cost savings for its proposed crack criteria updates in a subsequent filing.

Corrosion

The Associations' proposed changes to the corrosion repair criteria are expected to result in significant cost savings associated with avoiding excavations and repairs that are not necessary for safety. To provide a specific example, ILI technologies have improved substantially and can now provide data that allows operators to differentiate corrosion intersecting a longitudinal seam (which is often not a threat to integrity) versus metal loss that is preferentially affecting the longitudinal seam.

The Associations sought information from their members on excavations to comply with the current criteria for corrosion. In a useful example of criteria that do not drive safety improvement, two operators provided information on 2700 digs conducted pursuant to the long-seam corrosion criteria at Sec. 195.452(h)(4)(iii)(H) on two different pipeline systems totaling 6000 anomalies investigated. The results of these investigations found incidental corrosion features crossing or near the long seam weld but showed no evidence of preferential attack of the long seam weld. This effort resulted in an estimated **$135MM** spent with very little improvement in pipeline safety.

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[116] *See* Arnav Rana & Sanjay Tiku, Pipeline Rsch. Council Int'l, *Verification of Screening Tools for Classifying ILI Reported Dents with Metal Loss Features* (2023); Sanjay Tiku, Pipeline Rsch. Council Int'l, *Performance Evaluation of ILI Systems for Dents and Coincident Features* (2024), https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=20257&s=5B6EAFBE26AB49FA93493ACD715FF3AE&c=1.

[117] Matt Romney, Dane Burden & Mike Kirkwood, *The Power to Know More About Third Party Gouging, in* PROC. OF THE PIPELINE TECHNOLOGY CONF. (2022).

Dents

The Associations' proposed dent criteria would reduce costs by eliminating unnecessary excavations driven by the current, arbitrary dent depth criteria. The Associations propose to keep the depth-based criteria for dents but also allow operators the option apply modern ECA methods to determine if dents are a threat to pipeline integrity. One operator informed the Associations it would save **$1+ million annually** if it were permitted to use the Association's proposed dent criteria.

m. Management of Pipelines with Unknown Material Properties

Question – Section III.B.3

What methods do operators use to evaluate anomalies when material properties of a pipeline segment are unknown? What activities, if any, do operators perform to obtain unknown material property information for anomaly evaluation, and what incremental, per-unit costs are associated with those activities? Are there assumed or conservative values used when material properties are unknown, and what is the technical basis for those values (*e.g.,* operator-specific experience, or consensus industry standards and recommended practices)? How has obtaining material property information affected the classification of anomalies compared with using assumed or conservative values?

<u>Comments</u>:

When pipeline material properties are unknown or incomplete at an anomaly location, operators use conservative values, reasonably assumed values based on available information, or they attempt to obtain additional information. There are a variety of methods that can be used to fill data gaps on materials properties and which ones are appropriate depends on the specific context. Destructive testing of pipe samples in a lab, while more precise, may not always be feasible due to the need for cut-outs, which may interrupt service, create worker safety risks, cause business disruption and impose significant costs. Operators may also use the default values for pipe materials strength as allowed in Part 195.[118]

Recent innovation has led to new technologies and engineering tools to support reliable estimates of materials strength and properties at anomaly locations. For example, in-situ technologies for determining pipe grade have been developed as a more practical alternative to cut-outs. These technologies are often paired with a statistical model for predicting material properties using available historical data and pipe population trends. Advancements in ILI technology have provided a basis to help identify distinct material populations along the pipeline. Once these populations are defined, operators may conduct excavations to collect samples for in-situ or

[118] 49 CFR § 195.106(b)(2) allows the use of an X-24 default value for calculating design pressure.

laboratory testing to determine material properties for a certain population of pipe. Operators can also use values that are based on industry reference information and databases, installation year or era, manufacturing methods, pipe characteristics of then-available pipe, historical records, and other industry practice. Where the pipeline has a hydrotest record or documented operating pressure history, operators may use those values to estimate SMYS using the Barlow equation,[119] while applying appropriate safety factors.

n. Use of Failure Pressure-Based Criteria

Question – Section III.B.4

Should PHMSA consider adopting predicted failure pressure-based criteria for evaluating anomalies on hazardous liquid and carbon dioxide pipelines under part 195? If so, what is an appropriate method to predict failure pressure for different types of anomalies on different categories of hazardous liquid and carbon dioxide pipelines? Do hazardous liquid and carbon dioxide pipeline operators employ a predicted failure pressure-based response criterion for any anomalies on their facilities? Would such an approach be more appropriate for some types of anomalies (e.g., metal loss anomalies) than others? And would such a criterion be appropriate for all part 195-regulated hazardous liquid and carbon dioxide pipelines? What amendments to part 192 regulatory language would be necessary when applied to part 195-regulated hazardous liquid and carbon dioxide pipelines? Are the consensus industry standards referenced in part 192 regulations appropriate for calculating predicted failure pressure on hazardous liquid and carbon dioxide pipelines, and what alternatives may be appropriate to consider? Please provide the technical, safety, and economic reasons for any suggested regulatory amendments, noting in particular the potential compliance costs and implementation challenges associated with adopting a predicted failure pressure-based repair criterion.

Comments:

The Associations propose that PHMSA allow for the broader use of failure pressure-based criteria for evaluating and scheduling anomalies for repair. Operators can leverage these criteria to make better informed decisions about individual anomalies as compared to the current, prescriptive repair criteria. There is extensive technical support for adoption of failure pressure-based criteria and the Associations believe that pipeline safety will be improved if these criteria can be used.

To that end, the Associations propose several changes to Sec. 195.452(h), including provisions to allow the use of failure pressure-based repair criteria for corrosion and cracking. Specifically, the Associations propose a new Sec. 195.452(h)(1)(i), which would provide several additional methods for remaining strength calculations for crack, corrosion and metal loss anomalies. These calculations would then be used in the context of specific repair criteria to make decisions about the need for and timing of repairs. Specific methods, with supporting technical documentation for

[119] *See* 49 CFR § 195.106(a).

each, are provided below. The Associations also address this topic in their responses to ANPRM sections III.A.1, III.A.3, and III.B.2.

Additional methods, beyond those currently listed in Sec. 195.452(h) include the following:

- **PSqr**: This method is used for metal loss anomalies. The PSqr methodology estimates the remaining strength of corroded pipelines by calculating the pressure at which failure is predicted, using a squared pressure ratio (P^2) approach that incorporates defect geometry, material properties, and safety factors to ensure structural integrity.[120] Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[121]

- **API 579-1/ASME FFS-1**: This method is used for assessing metal loss, cracks and crack-like anomalies. API 579 Part 9 (Assessment of Crack-Flaws) provides three assessment levels and employs a Failure Assessment Diagram (FAD) approach to account failure by fracture and by plastic collapse. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[122]

- **PRCI MAT-8**: This method is used for blunt flaws, cracks and crack-like anomalies. The Materials Assessment Tool - Version 8 (MAT-8) also employs a FAD approach. It has been recently updated to include probabilistic analysis and is under review for inclusion in API 579-1/ASME FFS-1. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[123]

- **CorLAS:** CorLAS (Corrosion Life Assessment Software) was developed for the assessment of sharp, longitudinally orientated surface flaws in a cylinder subject to internal pressure (i.e. axial cracks). It includes empirical correlations between the J-integral and the yield and tensile strength and Charpy V-notch impact energy) derived from tests on pipeline

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[120] Mohammad Al-Amin ET AL., *Achieving Consistent Safety by Using Appropriate Safety Factors in Corrosion Management Program*, *in* 1 PROC. OF THE 2020 13TH INT'L PIPELINE CONF., PIPELINE AND FACILITIES INTEGRITY (2020).

[121] *See, e.g.,* Shahani Kariyawasam, Shenwei Zhang, Jason Yan, Terry Huang, Mohammad Al-Amin, & Erwin Gamboa, Plausible Profiles (Psqr) corrosion assessment model (2020).

[122] *See e.g.,* Andrew Cosham & Phil Hopkins, *The Pipeline Defect Assessment Manual, in* PROC. OF THE 2002 4TH INT'L PIPELINE CONF., 1565 (2002); Ted L. Anderson & David A. Osage, Am. Petroleum Inst., *API 579: A comprehensive fitness-for-service guide*, *in* 77 Int'l J. of Pressure Vessels and Piping, 953 (2000).

[123]*See e.g.,* Ted L. Anderson, Pipeline Rsch. Council Int'l, *Assessing Crack-Like Flaws in Longitudinal Seam Weld: A State-of-the-Art Review* (2017); Thomas Dessein ET AL., *Burst Pressure Prediction for Axial Cracks in Pipelines With Non-Ideal Depth Profiles, in* 2B PROC. OF THE 2024 15TH INT'L PIPELINE CONF., PIPELINE AND FACILITIES INTEGRITY (2024).

steels. Industry experience with this method demonstrates that it is sound and appropriate for inclusion in the regulations.[124]

- **Batelle NG-18 Ln-Sec and Modified Ln-Sec**: This method is used for axially oriented surface anomalies. NG-18 is a semi-empirical model for predicting the failure stress of a pressurized cylinder with a longitudinal crack like defect. Industry experience with this method demonstrates that it may not be appropriate for all circumstances, particularly for pipe seams with a seam joint factor less than 1 that operate in the brittle regime, but may be used for pipelines operating within the ductile regime.[125]

Proposed Changes to Part 195:

195.452(h)(1)

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(i) ***Calculation method(s).*** An operator must, for each anomaly, select an appropriate remaining strength calculation methodology that gives consideration to anomaly type. Material property values should be relevant for the anomaly under consideration. The circumstances of the pipe parameters and anomaly type must meet the applicability criteria of the remaining strength calculation methodology selected. Remaining strength calculations may include, but are not limited to, ASME/ANSI B31G/Modified B31G, PRCI PR-3-805 (R-STRENG), PSqr, API 579-1/ASME FFS-1, Batelle NG-18 Ln-Sec and Modified Ln-Sec, PRCI MAT-8, and CorLas. Based on the remaining strength calculation, an operator will determine the requirements for remediation as indicated in 195.452(h)(4).

Note: These updated calculation methods are part of the Associations' larger proposal to amend 195.452(h), set out in full in response to question III.A.1.

Technical, Safety, and Economic Justification for Proposed Changes:

Technical and Safety Justification

The use of engineering tools to determine the remaining strength and failure pressure of an anomaly is well understood and represents an improved approach for making repair determinations when compared to the prescriptive depth-based and other repair criteria. Specific technical support

[124] *See e.g.,* Ahmed Sellami ET AL., *Strain-Based Modeling of Burst Pressure in Pipelines with Selective Seam Weld Corrosion*, 217 Int'l J. of Pressure Vessels and Piping (2025); Raymond R. Fessler ET AL., *Predicting the Failure Pressure of SCC Flaws in Gas Transmission Pipelines, in* 2 PROC. OF THE 2012 9TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT 653 (2012).

[125] *See e.g.,* Andrew Cosham ET AL., *Crack-Like Defects in Pipelines: The Relevance of Pipeline-Specific Methods and Standards, in* 2 PROC. OF THE 2012 9TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT 713 (2012); Samarth Tandon ET AL., *Evaluation of Existing Fracture Mechanics Models for Burst Pressure Predictions, Theoretical and Experimental Aspects*, *in* 2 PROC. OF THE 2014 10TH INT'L PIPELINE CONF., PIPELINE INTEGRITY MANAGEMENT (2014).

for each proposed calculation method is provided at the beginning of this section. The Associations have also proposed added safety margins of 1.25x MOP when conducting remaining strength calculations under certain proposed 1-year conditions. The Associations based this safety margin on PRCI research[126] and expected changes to RP 1176.[127]

The use of modern, updated methods of evaluating anomalies will continue to help the industry better align resources on true safety threats. Any improvement in prioritizing resources on key issues and reallocating funding to other higher priority pipeline safety issues improves safety performance. Also, eliminating excavation activities to inspect and repair an anomaly that represents no threat to safety, operations, or reliability removes any potential for the unintended consequences of taking that action.

o. Repair Criteria and Remediation Timelines for Longitudinal Seam Weld Corrosion

Question – Section III.B.5

Are repair criteria and remediation timelines for hazardous liquid and carbon dioxide pipelines appropriate for metal loss anomalies on a longitudinal seam for HCA and non-HCA segments? How do operators evaluate metal loss anomalies on a longitudinal seam? Are there innovative technologies or methods for improved evaluation of metal loss anomalies on a longitudinal seam that could justify amendments to the repair criteria for HCA segments at § 195.452? Please identify any specific regulatory amendments that merit reconsideration, as well as the technical, safety, and economic reasons supporting those recommended amendments.

Comments:

The Associations propose revisions to the repair criteria related for corrosion on the longitudinal seam weld. The response criteria in Sec. 195.452(h)(4)(iii)(H) requires repair of "corrosion of or along a longitudinal seam weld," which has been interpreted by PHMSA to require repair of any corrosion anomaly that intersects or is closely aligned with a longitudinal seam weld, many of which represent no threat to pipeline integrity. This has resulted in thousands of unwarranted anomaly repair excavations, resulting in millions of dollars of repair costs that provide no safety benefit.

PHMSA has recognized this issue in recent changes to the repair criteria for gas transmission lines.[128] The Association's proposed amendments mirror the Part 192 revisions and defines the

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[126] *See* Cara Macrory, Pipeline Rsch. Council Int'l, *Considerations for Crack ILI Response in Hazardous Liquids Pipelines* (2022).

[127] Am. Petroleum Inst., Recommended Practice 1176: Assessment and Management of Cracking in Pipelines, (1st ed. 2016) The second edition of API RP 1176 is expected in late 2025 or early 2026.

[128] For the amendments to the gas repair criteria, PHMSA noted that "[c]orrosion that 'preferentially' affects the long seam is corrosion that is of and along the weld seam that is classified as selective seam weld corrosion." Pipeline

relevant corrosion as metal loss that may be "preferentially affecting a longitudinal seam." This change will ensure that resources are being focused on conditions that represent a threat to pipeline integrity. The proposed changes also reflect the language that is currently applicable to gas pipelines in 192.714 and 192.933.[129]

<u>Proposed Changes to Part 195:</u>

49 CFR § 195.452(h)

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> (ii) ***1 year conditions.*** Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 1 year of discovery of condition, unless an extended schedule is established in accordance with paragraph (h)(4)(iii) of this section…
>
> > (I) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0.

Note: This revised longitudinal seam weld corrosion language is part of the Associations' broader proposal to amend 195.452(h), set out in full in response to question III.A.1.

<u>Technical, Safety, and Economic Justification for Proposed Changes:</u>

Technical and Safety Justification

ILI technologies have improved substantially and can now provide data that help operators differentiate corrosion intersecting a longitudinal seam (which is often not a threat to integrity) versus metal loss that is preferentially affecting or align with a longitudinal seam.[130]

The Associations respectfully request that PHMSA revise Sec. 195.452(h)(4)(iii)(H) so that the response criteria wording for hazardous liquid pipelines aligns with the response criteria established for natural gas transmission pipelines. Consistency in the response criteria is appropriate as it focuses on the threat to pipeline integrity, regardless of the material being transported, and will remove ambiguity associated with the current criterion in the hazardous liquid pipeline safety regulations. Many pipeline operators have both hazardous liquid and natural gas

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Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, 87 Fed. Reg. 52,224, 52,250 (Aug. 24, 2022).

[129] 49 C.F.R. § 192.714(d)(2)(vi), (d)(3)(v); 49 C.F.R. § 192.933(d)(2)(v), (d)(3)(v).

[130] *See* Michael Turnquist, Pipeline Rsch. Council Int'l, *Response to Corrosion Intersecting the Longitudinal Seam in Liquid Pipes* (2024).

transmission pipeline assets and would benefit from a consistent application of the response criterion for metal loss preferentially affecting a longitudinal seam.

The proposed change will improve safety by focusing on conditions that require response and eliminating the thousands of excavations that have been performed to address metal loss based on the ambiguous criterion that has been in place for decades. Avoiding excavations that are not required to maintain pipeline safety removes the potential for unintended consequences related to any construction activity, and reduces environmental impact, and avoids disruptions in energy product supply.

Cost Justification

The Associations' proposed changes are expected to result in significant cost savings associated with reduced excavations. ILI technologies have improved substantially and can now provide data that help operators differentiate corrosion intersecting a longitudinal seam (which is often not a threat to integrity) versus metal loss that is preferentially affecting the longitudinal seam.

The Associations sought information from their members on excavations to comply with the current criteria for corrosion. In a useful example of criteria that do not drive safety improvement, two operators provided information on 2700 digs conducted pursuant to the long-seam corrosion criteria at Sec. 195.452(h)(4)(iii)(H) on two different pipeline systems totaling 6000 anomalies investigated. The results of these investigations found incidental corrosion features crossing or near the long seam weld but showed no evidence of preferential attack of the long seam weld. This effort resulted in an estimated **$135MM** spent between two operators with very little improvement in pipeline safety.

p. Repair Criteria and Remediation Timelines for Dents and Mechanical Damage Anomalies

Question – Section III.B.6 Are repair criteria and remediation timelines for hazardous liquid and carbon dioxide pipelines appropriate for dents and mechanical damage anomalies on HCA and non-HCA segments? How do operators evaluate dent and mechanical damage anomalies? Are there innovative technologies or methods (*e.g.,* engineering critical assessments, or ECAs) for improved evaluation of dents and mechanical damage anomalies that could justify adjustment of the repair criteria for such anomalies? What ECA methodologies (*e.g.,* API RP 1183) or elements thereof, such as safety factors, and finite element analysis, would be appropriate for use? What elements and supportive records are necessary for an effective ECA of a dent or mechanical damage anomaly on a hazardous liquid or carbon dioxide pipeline? Are there circumstances (*e.g.,* operating environments; physical characteristics of the commodity transported) where ECAs would be an inappropriate or challenging tool for evaluating dents and mechanical damage anomalies on different categories of hazardous liquid and carbon dioxide pipelines? Please provide the technical, safety, and economic reasons for any recommended amendments, noting in particular any potential program implementation costs and unit costs of each ECA conducted, avoided compliance costs due to deferred repair or for another reason, and implementation challenges.

Comments:

The Associations propose several changes to the repair criteria in Sec. 195.452(h) for dents. These proposed changes reflect 20+years of industry experience in management of dents and incorporate findings from extensive PHMSA and industry funded research and development programs. The process used by most pipeline operators generally follows the data evaluation processes included in API RP 1183. This consists of a tiered approach from initial data integration and screening (e.g., dent shape and profile, indications of coincident features within or near the dent, pressure cycling severity at anomaly locations) to a full ECA using finite element analysis and other detailed models for estimating remaining fatigue life and critical strain limits for each dent.

As detailed in the Associations proposed revisions to Sec. 195.452(h), the Associations are proposing several changes to dent repair criteria that includes moving 60-day and 180-day response conditions to a 1-year response timeline, increasing the level of metal loss within a dent that requires response, and allowing for an ECA to be performed to evaluate dent repair timelines as an alternative to the prescriptive depth/interacting features based response criteria. The ECA includes consideration of safety factors and provides guidelines for FEA analysis. In addition, several changes are proposed to distinguish between dents with gouging, cracking, and metal loss not caused by mechanical damage to the pipeline. The changes related to metal loss and gouging relate to ILI systems having improved capabilities to corrosion from gouging.[131] Many unnecessary digs are performed to evaluate dents that overlap coincidental corrosion that is not a significant integrity threat.

Proposed Changes to Part 195:

195.452(h)(4)

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> (i) ***Immediate repair conditions.*** An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce the operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure ~~using the formulas referenced in paragraph (h)(4)(i)(B)~~ pursuant to paragraph (h)(1)(i) of this section. If no suitable remaining strength calculation method can be identified, an operator must lower its operating pressure to 40% SMYS or implement a ~~minimum~~ 20% ~~percent or greater~~ operating pressure reduction, based on ~~actual~~ the highest operating pressure for two months prior to the date of inspection, until the anomaly is repaired. An operator must treat the following conditions as immediate repair conditions:

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[131] *See, e.g.,* Matt Romney, Dane Burden & Mike Kirkwood, *The Power to Know More About Third Party Gouging, in* PROC. OF THE PIPELINE TECHNOLOGY CONF. (2022); J. Ludlow, "Enhancing Metal Loss Sizing Using Multiple Data Sets," Pipeline Pigging and Integrity Management Conference (2014).

(~~C~~E) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of ~~metal loss, cracking, or a stress riser~~ cracking, gouging, or metal loss that is determined by the operator to likely be caused by mechanical damage, unless an extended schedule is established in accordance with paragraph 195.452(h)(4)(iii) of this section.

(~~D~~F) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter, unless an extended schedule is established in accordance with paragraph 195.452(h)(4)(iii) of this section.

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(ii) ***1 year conditions.*** Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 1 year of discovery of condition, unless an extended schedule is established in accordance with paragraph (h)(4)(iii) of this section:

(A) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than ~~3~~2% of the pipeline nominal diameter or ~~(~~greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12~~)~~.

(B) A dent located on the bottom of the pipeline that has any indication of ~~metal loss, cracking, or a stress riser~~ cracking, gouging, or metal loss that is determined by an operator to be caused by mechanical damage.

~~A~~C) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

(~~C~~D) A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.

(E) A dent located anywhere on the pipe with metal loss >20% in depth that is determined by the operator to be caused by corrosion and is not the result of mechanical damage to the pipeline.

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(iii) ***Extended Schedule Conditions.*** To establish an extended schedule, an operator must:

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(B) Conduct an Engineering Critical Assessment (ECA) for dents that considers:

1. The size, location, and when appropriate, the shape of the dent.

2. 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. A review of metal loss, 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 prior inline inspections.

4. 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. An evaluation of 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 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. 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.

<u>Technical, Safety, and Economic Justification for Proposed Changes:</u>

The Associations propose this ECA alternative to the prescriptive repair criteria for dents because it is well understood that the specific shape of a dent and operating conditions affect its level of risk. Dent shape and operating conditions allow for a more accurate determination of risk than using just dent depth.

The introduction of the first edition of API RP 1183 in 2020 provided a holistic framework for the management of pipeline dents and was an important milestone for the industry. [132] A key part of pipeline dent management in API 1183 is the understanding that tiered ECAs (or fitness for service) are possible and may rely on multiple methods.

The Associations' proposed ECA language provides a framework that operators may use to supplement the proposed prescriptive dent repair criteria. Dent ECAs may require robust data integration and use safety factors to account for loading, model, measurement, and material uncertainties. These elements are included in the Associations' proposed ECA language and are built on integrity management principles in accepted industry standards, including ASME B31.8S[133] and API 1160.[134]

The ECA methods in API 1183 are based on decades of pipeline industry experience and show that ECA processes for a dent should consider two types of assessments, fatigue and strain-based evaluations.

- Strain-based evaluations are recognized by the industry and have appeared in ASME B31.8 for over two decades (non-mandatory appendix R of ASME B31.8 and in CSA-Z662). Strain-based methods have continued to evolve and there has been significant work in this area in recent years to account for more parameters and uncertainties.[135] Strain-based evaluations are a key part of dent assessments.

- Fatigue based evaluations are a key part of dent assessments and industry papers and projects have developed technical methods and validation for many of the commonly used fatigue-based methods. Notably, PRCI reports show the amount of work that went into development of just one of the methods presented in API RP 1183.[136] Additionally, validation work using full scale fatigue testing of field dents presented in additional PRCI research exemplifies how these methods are being validated and improved through organizations like PRCI.[137] Many other individual papers have been published with respect

[132] Am. Petroleum Inst., Recommended Practice 1183: Assessment and Management of Pipeline Dents (1st ed. 2020).

[133] The Am. Soc'y of Mech. Eng'r, B31.8S - Managing System Integrity of Gas Pipelines, (2022).

[134] Am. Petroleum Inst., Recommended Practice 1160, Managing System Integrity for Hazardous Liquid Pipelines (3rd ed. 2019, reaffirmed 2024).

[135] *See* Arnav Rana ET AL., Pipeline Rsch. Council Int'l, *Improve Dent-Cracking Assessment Methods* (2022).

[136] *See* Sanjay Tiku ET AL., Pipeline Rsch. Council Int'l, *Fatigue Life Assessment of Dents with and without Interacting Features*.

[137] *See* PRCI MD-4-15, Performance of Dent Fatigue Models for Natural Dents Removed from Service.

to other fatigue methods.[138] Ultimately, fatigue-based evaluations are a key part of dent assessments.

The presence of interacting features (e.g., metal loss, gouges, cracks etc.) may impact the results of the strain and fatigue assessments of dents. Operators have also investigated the ability of ILI to provide information about interacting threats via large PRCI projects.[139] Key findings from these projects show that the uncertainties in measurement (POD and sizing) are generally on the same order as what is accepted for stand-alone features such as metal loss or cracks. The presence and integrity impact of these features can be accounted for in assessments. Additionally, advancements in ILI technology and analysis have made it possible to identify gouging and mechanical-damage related metal loss during inspections.[140] Operators also have access to multiple inline inspection data sets, right-of-way surveillance, and depth cover information that can be used for robust data integration to identify mechanical damage features.

Allowing operators to use the Associations' proposed dent criteria would allow operators to better manage risk and eliminate unnecessary digs and repairs driven by the current requirements. One operator informed the Associations that the proposed dent repair criteria would drive savings of **$1+ million annually.**

q. Repair Criteria and Remediation Timelines for Dents with Metal Loss and Other Interacting Integrity Threats

Question – Section III.B.7

Are repair criteria and remediation timelines for hazardous liquid and carbon dioxide pipelines appropriate for dents with metal loss or other interacting integrity threats on HCA and non-HCA segments? 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 merit evaluation for incorporation by reference in PHMSA regulations? Please identify any specific regulatory amendments that merit consideration, as well as the technical, safety, and economic reasons supporting them.

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138 *See* R. L. Dotson ET AL., *Combining High Resolution In-Line Geometry Tools and Finite Element Analysis to Improve Dent Assessments*, *in* PROC. OF THE PIPELINE PIGGING AND INTEGRITY MANAGEMENT CONFERENCE, (2014).

139 *See* Arnav Rana & Sanjay Tiku, Pipeline Rsch. Council Int'l, *Verification of Screening Tools for Classifying ILI Reported Dents with Metal Loss Features* (2023); Sanjay Tiku, Pipeline Rsch. Council Int'l, *Performance Evaluation of ILI Systems for Dents and Coincident Features* (2024), https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=20257&s=5B6EAFBE26AB49FA93493ACD715FF3AE&c=1.

140 *See* Matt Romney, Dane Burden & Mike Kirkwood, *The Power to Know More About Third Party Gouging, in* PROC. OF THE PIPELINE TECHNOLOGY CONF. (2022).

<u>Comments</u>:

The Associations reiterate their support for the use of ECA to manage dents on pipeline segments, including in instances where there is a dent with metal loss and other interacting integrity threats. The Associations' proposed amendments to Sec. 195.452(h) provide the necessary safeguards to ensure that all dents are appropriately evaluated and managed.

<u>Proposed Changes to Part 195:</u>

195.452(h)(4)

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(i) ***Immediate repair conditions.*** An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce the operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure ~~using the formulas referenced in paragraph (h)(4)(i)(B)~~ pursuant to paragraph (h)(1)(i) of this section. If no suitable remaining strength calculation method can be identified, an operator must lower its operating pressure to 40% SMYS or implement a ~~minimum~~ 20% ~~percent or greater~~ operating pressure reduction, based on ~~actual~~ the highest operating pressure for two months prior to the date of inspection, until the anomaly is repaired. An operator must treat the following conditions as immediate repair conditions:

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(~~C~~E) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of ~~metal loss, cracking, or a stress riser~~ cracking, gouging, or metal loss that is determined by the operator to likely be caused by mechanical damage, unless an extended schedule is established in accordance with paragraph 195.452(h)(4)(iii) of this section.

(~~D~~F) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter, unless an extended schedule is established in accordance with paragraph 195.452(h)(4)(iii) of this section.

***

(ii) ***1 year conditions.*** Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 1 year of discovery of condition, unless an extended schedule is established in accordance with paragraph (h)(4)(iii) of this section:

(A) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than ~~3~~2% of the pipeline nominal diameter or ~~(~~greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12~~)~~.

(B) A dent located on the bottom of the pipeline that has any indication of ~~metal loss, cracking, or a stress riser~~ cracking, gouging, or metal loss that is determined by an operator to be caused by mechanical damage.

~~A~~C) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

(~~C~~D) A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.

(E) A dent located anywhere on the pipe with metal loss >20% in depth that is determined by the operator to be caused by corrosion and is not the result of mechanical damage to the pipeline.

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(iii) ***Extended Schedule Conditions.*** To establish an extended schedule, an operator must:

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(B) Conduct an Engineering Critical Assessment (ECA) for dents that considers:

1. The size, location, and when appropriate, the shape of the dent.

2. 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. A review of metal loss, 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 prior inline inspections.

4. 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. An evaluation of 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 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. 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.

<u>Technical, Safety, and Economic Justification for Proposed Changes:</u>

ECA can be used to effectively evaluate a dent with an interacting feature, as the interacting feature may impact the results of the strain and fatigue assessments of dents. Additionally, the use of ILI to generate information about interactive threats has been the subject of several PRCI projects.[141] These projects show that the uncertainties in measurement (POD and sizing) are generally on the same order as what is accepted for stand-alone features such as metal loss or cracks. Therefore, the presence and integrity impact of these features can be accounted for in assessments. Additionally, advancements in ILI technology and analysis have made it possible to identify gouging and mechanical damage-related metal loss during inspections.[142] Operators also have access to multiple inline inspection data sets, right-of-way surveillance, and depth cover information that can be used for robust data integration to identify mechanical damage features. Therefore, operators can use ECA to effectively manage dents with metal loss or other interacting features.

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[141] *See* Arnav Rana & Sanjay Tiku, Pipeline Rsch. Council Int'l, *Verification of Screening Tools for Classifying ILI Reported Dents with Metal Loss Features* (2023); Sanjay Tiku, Pipeline Rsch. Council Int'l, *Performance Evaluation of ILI Systems for Dents and Coincident Features* (2024), https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=20257&s=5B6EAFBE26AB49FA93493ACD715FF3AE&c=1.

[142] *See* Matt Romney, Dane Burden & Mike Kirkwood, *The Power to Know More About Third Party Gouging, in* PROC. OF THE PIPELINE TECHNOLOGY CONF. (2022).

Moving away from the current, arbitrary dent repair criteria to the Associations' proposals would allow operators to eliminate unnecessary digs and repairs while maintaining a high level of pipeline safety. One operator informed the Associations it would save **$1 million or more** on an annual basis that could be deployed to other critical integrity projects.

r. In-Service Part 195 Breakout Tanks – Adopting a Risk-Based Approach

Question – ANPRM Section III.D.1

How should part 195 regulations address the assessment of and remediation of anomalies on in-service breakout tanks? Would incorporating the risk-based inspection interval provided for in consensus industry standards (*e.g.,* the fifth edition of API Std 653) within PHMSA regulations be appropriate for some or all breakout tanks? Please identify any specific regulatory amendments that merit consideration, as well as the technical, safety, and economic reasons supporting those recommended amendments.

Comments:

The Associations request that PHMSA update Sec. 195.432 and the relevant incorporation by reference provision in Sec. 195.3 to permit operators to use the most current version of API Standard 653— the 5th edition, including Addendums 1, 2, and 3—in full and without exceptions, for assessing and remediating anomalies in in-service breakout tanks. The Associations believe that 653 inspections are an important means of maintaining tank integrity and safety. These goals can be realized more efficiently if operators are allowed to apply the latest version of API Standard 653, including the risk-based inspection (RBI) provisions of the standard.

Adopting the latest version of this standard would enable operators to apply a consistent, technically justified approach to the inspection and maintenance of breakout tanks built under API Standard 650 across multiple jurisdictions and regulatory agencies and programs. This regulatory amendment is appropriate for all breakout tanks, as it provides clear guidance for conducting inspections and repairs necessary to maintain tank integrity, while providing to the public, regulators, operators and the industry in general, more benefits than the current version incorporated by reference in Sec. 195.3(b)(18), including:

1. **Reduced Leak Risk**: Encourages the use of leak prevention, detection, corrosion mitigation, containment safeguards, and engineering-based methodologies to establish safe inspection intervals.
2. **Improved Safety**: Minimizes unnecessary exposure to hazardous environments and confined spaces by personnel performing tank cleaning and inspection more frequently than needed. For higher risk tanks, application of risked based approach would also result in more frequent inspections than the maximum prescriptive interval.
3. **Enhanced Effectiveness and Efficiency**: Enables operators to determine inspection and reinspection intervals based on threats, safeguards, and risks—enhancing the effectiveness

of asset integrity programs. This approach also reduces operational costs, avoids unnecessarily removing tanks from service when no repairs are needed and supports the continuity of critical infrastructure by staggering tank outages.

4. **Greater Reliability**: Facilitates informed, risk-based decisions by applying API RP 580 principles (which are referenced in the risk-based inspection (RBI) provisions of API Standard 653) and engineering assessments verified by qualified tank engineers or corrosion specialists. This approach requires periodic review and confirmation, offering a proactive, data-driven alternative to fixed inspection intervals that only reassess data during internal inspections.

5. **Environmental Benefits**: Reduces emissions and hazardous waste by avoiding unnecessary tank cleanouts, which release VOCs and GHGs.

6. **Standardized Practices**: Promotes consistency and clarity across operators by providing specific guidance on the application of API Standard 653, incorporating updated references to ASME and other relevant codes, and offering clearer direction for inspection and repair procedures.

7. **Modernized Techniques**: Incorporates proven technologies and analytical methods to improve inspection and repair quality.

8. **Industry-Wide Safety Improvements**: Leverages decades of industry experience reflected in the latest updates, corrections, and clarifications.

9. **Reduced Human Error**: Simplifies compliance by using a single standard across all jurisdictions and assets built to API 650.

10. **Innovation Incentives**: Encourages investment in advanced analytics, inspection and repair techniques, by moving away from rigid time-based inspection schedules.

For a summary of the main changes between the currently incorporated version of API Standard 653 and subsequent updates to that standard, please refer to Annex A.

By adopting the 5th edition of API Standard 653, including Addendums 1, 2, and 3—in full and without exceptions, for assessing and remediating anomalies in in-service breakout tanks, PHMSA can achieve greater levels of safety in a more efficient manner. Specifically, this approach incentivizes the use of tank safeguards and grounds inspection intervals in engineering assessments, reducing unnecessary tank outages and minimizing personnel exposure to hazardous environments. This approach enhances leak prevention, improves asset reliability, and supports the use of modern inspection technologies. Environmentally, it cuts emissions and hazardous waste by avoiding excessive cleanouts. Economically, it offers an estimated **$220 million** in annual savings by optimizing inspection schedules. Overall, the proposed revisions promote standardized, data-driven practices that improve safety, efficiency, and environmental stewardship across the industry.

Proposed Changes to Part 195:

49 CFR § 195.3(b)(18)

API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction," ~~3rd edition, December 2001, (including addendum 1 (September 2003), addendum 2 (November 2005), addendum 3 (February 2008), and errata (April 2008))~~ 5th edition, November 2014, (including addendum 1 (April 2018), addendum 2 (May 2020), addendum 3 (November 2023), errata 1 (March 2020), errata 2 (February 2025)), (API Std 653), IBR approved for §§ 195.205(b), 195.307(d), and 195.432(b).

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49 CFR § 195.205(b)

(1) For tanks designed for approximate atmospheric pressure, constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated; and for tanks built to API Std 650 (incorporated by reference, *see* § 195.3) or its predecessor Standard 12C; repair, alteration; and reconstruction must be in accordance with API Std 653, 5th edition ~~(except section 6.4.3)~~ (incorporated by reference, *see* § 195.3).

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49 CFR § 195.432(b)

Each operator must inspect the physical integrity of in-service atmospheric and low-pressure steel above-ground breakout tanks according to API Std 653 ~~(except section 6.4.3, Alternative Internal Inspection Interval)~~ (incorporated by reference, see § 195.3). However, if structural conditions prevent access to the tank bottom, its integrity may be assessed according to a plan included in the operations and maintenance manual under § 195.402(c)(3). ~~The risk-based internal inspection procedures in API Std 653, section 6.4.3 cannot be used to determine the internal inspection interval.~~

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49 CFR § 195.432(b)(1)[143]

~~(1) Operators who established internal inspection intervals based on risk-based inspection procedures prior to March 6, 2015 must re-establish internal inspection intervals based on API Std 653, section 6.4.2 (incorporated by reference, *see* § 195.3).~~

~~(i) If the internal inspection interval was determined by the prior risk-based inspection procedure using API Std 653, section 6.4.3 and the resulting calculation exceeded 20 years, and it has been more than 20 years since an internal inspection was performed, the operator must complete a new internal inspection in accordance with § 195.432(b)(1) by January 5, 2017.~~

[143] The Associations propose to strike existing § 195.432(b)(1) because all of the deadlines in that regulations have long since passed.

~~(ii) If the internal inspection interval was determined by the prior risk-based inspection procedure using API Std 653, section 6.4.3 and the resulting calculation was less than or equal to 20 years, and the time since the most recent internal inspection exceeds the re-established inspection interval in accordance with § 195.432(b)(1), the operator must complete a new internal inspection by January 5, 2017.~~

~~(iii) If the internal inspection interval was not based upon current engineering and operational information (i.e., actual corrosion rate of floor plates, actual remaining thickness of the floor plates, etc.), the operator must complete a new internal inspection by January 5, 2017 and re-establish a new internal inspection interval in accordance with § 195.432(b)(1).~~

Technical, safety, and economic reasons supporting the recommended amendments

PHMSA currently regulates over 8,500 breakout storage tanks across North America (Figure 1). The majority of these tanks are constructed in accordance with API Standard 650 and maintained under API Standard 653. Under the existing regulations—Sections 195.3(b)(18), 195.205(b)(1), and 195.432(b)—tanks must undergo internal inspection (requiring them to be taken out of service) within 10 years of initial service and at intervals not exceeding 20 years thereafter. This prescriptive requirement currently applies regardless of whether the tank has safeguards or an operator has data that supports the good condition of the tank and the use of a longer inspection interval.

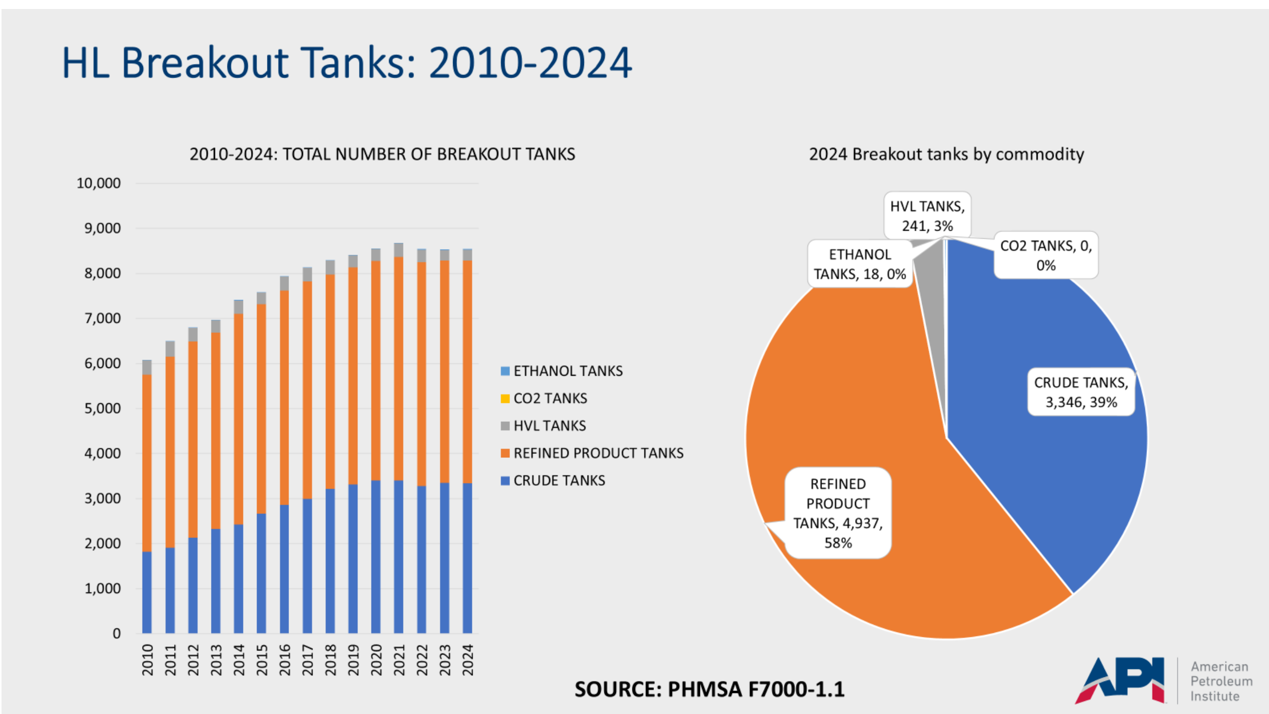

Figure 1.
Hazardous Liquids (HL) Breakout Tanks population

Source: American Petroleum Institute (API), Tank Analysis Data Trends (using PHMSA Form 7000-1 data)

As a result, approximately 425 regulated tanks are inspected annually, with associated safety, environmental, and economic impacts, as detailed in the following sections.

This regulatory amendment proposes that PHMSA allow operators to adopt the most current version of consensus industry standards. This would enable the use of sound engineering principles, including but not limited to, Tank Safeguard credits, Similar Service Assessments (SSA), and RBI methodologies to determine inspection intervals.

Industry experience with non-DOT regulated tanks—where the 5th edition of API Standard 653, including Addendums 1, 2, and 3 has been implemented—demonstrates that high-quality data and comprehensive engineering assessments can be used to determine appropriate inspection frequencies. These intervals may be shorter or longer than the current 20-year maximum, depending on factors such as design, construction, operation, maintenance history, environmental conditions, and prior inspection results.

API conducted a survey of seven industry members that operate approximately 6,500 PHMSA-regulated and unregulated tanks. The following quantification of benefits is based on aggregated data from these seven operators, who together manage 25.7% of all breakout storage tanks regulated by PHMSA, including both crude oil and non-crude oil tanks, making this a representative sample of the industry.

From that survey, data drawn from 60 industry assessments, including RBI and other engineering evaluations, indicated that while some tank inspections could be safely deferred, others required acceleration. To support the proposed rulemaking, the average inspection interval—calculated across both deferred and advanced inspections—was determined to be 25.63 years. For simplicity and consistency, a 25-year interval will be used as the baseline for evaluating the rule's potential benefits. Under this scenario, the number of tanks inspected annually would decrease by 85 (20%), resulting in an average of 340 inspections per year. This reduction in inspections would yield the following benefits:

1. **Reduced Leak Risk**
   Encourages the use of leak prevention, detection, corrosion mitigation, containment safeguards engineering-based methodologies to establish inspection intervals.

The 5th edition of API Standard 653, including Addendums 1, 2, and 3, incentivizes operators to add additional tank safeguards to atmospheric storage tanks, by allowing incremental credits on the initial inspection interval. Safeguards address the number one bottom failure mechanism for breakout tanks: corrosion (see Figure 2.). Whether corrosion or material related, tank bottom defects cannot be detected without an internal inspection. Safeguards such as thicker or stainless-steel bottom plates and internal liners reduce the likelihood of failure and release prevention barriers mitigate the consequences of failure. The current regulations, which do not allow this crediting mechanism, disincentivize the use of these additional safeguards.

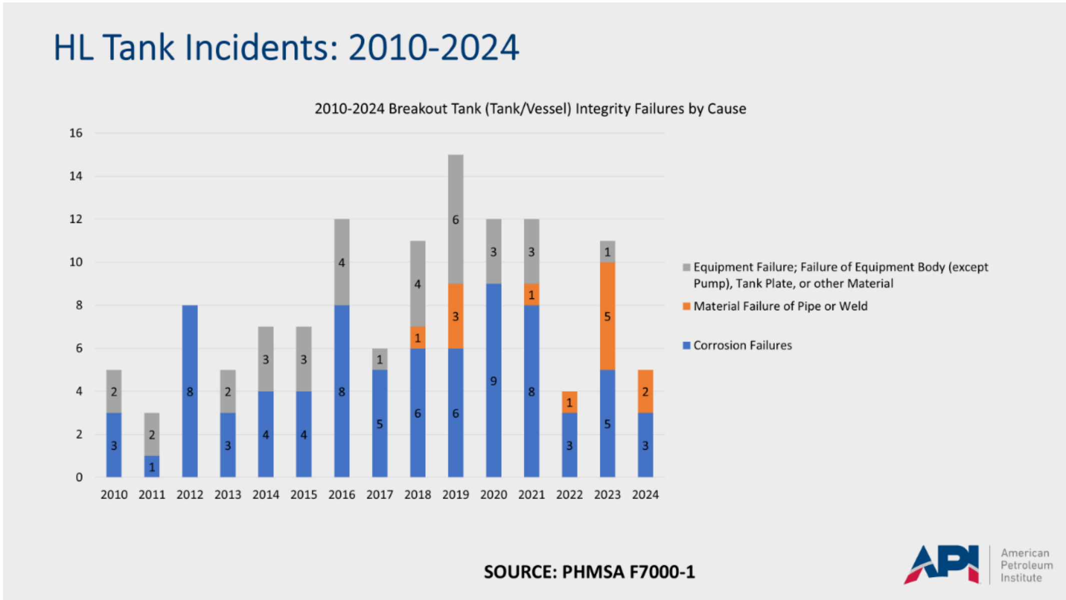

Figure 2.
Hazardous Liquids (HL) Tank Failures by Cause
Source: American Petroleum Institute (API), Tank Analysis Data Trends (using PHMSA Form 7000-1 data)

RBI is a proven methodology widely used across various asset types and has demonstrated effectiveness in reducing leaks and improving integrity management.

At the 2022 API Inspection and Mechanical Integrity Summit, operators reported that since implementing RBI for piping in refining operations, overall loss of containment events decreased by 15%, while incidents involving high-consequence services dropped by 70%. Similarly, one midstream company has observed up to a 50% reduction in leaks after adopting RBI for facility piping systems.

2. **Improved Safety**
   Minimizes unnecessary personnel exposure to hazardous environments and confined spaces by avoiding unnecessarily frequent internal inspections.

For each internal inspection that requires tanks to be taken out of service, API's industry survey demonstrates that the oil and gas industry dedicates approximately 64 person-hours per thousand barrels of liquid to tasks such as cleaning, inspection, and repair—many of which are performed in confined spaces. Over 32% of these hours involve exposure to hazardous atmospheres.

With around 425 tanks maintained annually, the industry spends nearly 4.6 million person-hours in confined spaces each year, with at least 1.5 million hours involving exposure to hazardous conditions.

Adopting the 5th edition of API Standard 653, including Addendums 1, 2, and 3, PHMSA can help the industry reduce exposure by at least 20%. This would result in a reduction of 912,000 person-hours spent in confined spaces and 294,000 hours of exposure to hazardous atmospheres.

In addition, when operators are allowed to use data and apply the RBI interval process, that effort will sometimes result in inspection intervals shorter than the current maximum non-RBI interval in Standard 653. Specifically, engineering assessments and RBI methodologies have shown that shorter inspection intervals may be warranted in some cases, challenging the assumption that a fixed 20-year interval is always appropriate or conservative. These outcomes demonstrate that a data-driven approach is the best path to increased safety.

3. **Enhanced Effectiveness and Efficiency and Greater Reliability**
   Enables operators to determine inspection and reinspection intervals based on threats, safeguards, and risk—enhancing the effectiveness of asset integrity programs. This approach would also reduce operational costs and supports the continuity of critical infrastructure by staggering tank outages.

The Associations' proposal facilitates informed**,** risk-based decisions by applying API RP 580 principles and engineering assessments[144] verified by qualified tank engineers or corrosion specialists. This approach requires review and periodic re-approval, offering a proactive, data-driven alternative to fixed inspection intervals that only reassess data during internal inspections.

As noted earlier, industry experience with non-DOT regulated tanks—where the 5th edition of API Standard 653 (including Addendums 1, 2, and 3) has been implemented—demonstrates that high-quality data and comprehensive engineering assessments can effectively determine appropriate inspection intervals. These intervals may be longer or shorter than the current 20-year maximum, depending on factors such as tank design, construction, operational history, maintenance practices, environmental conditions, and prior inspection results.

To assess the feasibility of applying this approach to DOT Part 195-regulated breakout tanks, operators performed engineering-based evaluations—such as risk-based and safeguard-informed inspections—and compared the results to recent out-of-service inspection data. The following case study illustrates findings that are consistent across multiple operators.

a. Operator Case Study:

The Associations obtained data from an operator which illustrates how the current prescriptive interval can result in a premature tank inspection. A 150-foot diameter by 48-foot high breakout tank was inspected in accordance with the third edition of API 653. An MFL (Magnetic Flux Leakage) scan of the tank bottom revealed no major findings. The lowest bottom thickness reading was 0.307 inches, indicating a corrosion rate of 0.9 mils/year and an estimated bottom life of 285

[144] API Standard 653, 5th Ed. references RP 580 principles in section 6.4.2.2.2 regarding the development of RBI intervals.

years. Under the currently adopted 3rd edition of the API 653 guidelines, this tank would be scheduled for another out-of-service inspection in 20 years.

An alternative in-service inspection evaluation was also performed using the Tank Safeguard Table referenced in API 653, 5th edition, Section 6.4.2.1.1. The tank is equipped with several safeguards:

- Thin film liner (+2 years)
- Cathodic protection (+5 years)
- Release prevention barrier with leak detection (+10 years)
- 5/16" bottom plate (+4.2 years)

These safeguards support extending the inspection interval by an additional 21.2 years, allowing for a total inspection interval of 41.2 years. However, API 653 5th Ed (latest version) 6.4.2. limits the inspection interval to 30 years when using Tank Safeguard credits. Therefore, in this example, the tank's next internal inspection would be scheduled in 30 years or less (depending on any future inspection results, or further limitations from the operator's own policies).

4. **Operational Considerations:**

In terminals where multiple tanks are constructed and commissioned simultaneously, current regulations require initial inspections within the same year. Without the flexibility provided by tank safeguards and engineering (including RBI) assessments, this can lead to significant disruptions in critical infrastructure due to simultaneous tank outages. Applying safeguard-based evaluations allows operators to stagger inspections, reducing operational impact and avoiding unnecessary early inspections.

5. **Economic Impact**
   Would save approximately $220 million annually, and improve safety outcomes, by allowing for data-driven, risk-based inspection instead of a one-size-fits-all prescriptive approach.

Adopting the 5th edition of API Standard 653 would allow operators to set inspection intervals based on tank safeguards and engineering assessments, rather than fixed timelines. This flexibility supports staggered maintenance schedules, reducing disruptions to critical infrastructure. It also offers significant economic benefits: with internal inspections costing approximately $15.48 per barrel of tank volume the total cost of inspecting all regulated tanks every 20 years is estimated at $1.1 billion. By applying a risk-based approach, operators could reduce these costs by 20%—saving roughly $220 million annually, or over $2.2 billion over a decade. These savings could be reinvested in safety enhancements, infrastructure upgrades, or other high-priority initiatives. Again, as discussed above, this change is also likely to improve safety.

6. **Environmental Benefits**
   Reduces emissions and hazardous waste by avoiding unnecessary tank cleanouts, which release VOCs and GHGs.

   a. **Case Study: Environmental Impact of Breakout Tank Maintenance (600,000 bbl tank)**

When a breakout tank is vented for cleaning and inspection, it releases significant volumes of volatile organic compounds (VOCs). An operator case study demonstrates that a single 600,000-barrel tank can emit up to 70 tons of VOCs during this process.

While vapor destruction systems can mitigate these emissions, they rely on propane combustion—resulting in approximately 500 tons of CO_2-equivalent (CO_2e) emissions per tank.

Additional emissions stem from construction activities required for cleaning and repair. Equipment such as generators, compressors, cranes, and work trucks contribute an estimated 2,500 tons of CO_2e per tank.

Each internal inspection also generates substantial waste, including:

- 11,000 barrels (1,650 tons) of crude sludge
- 250 tons of blast media
- 80,000 gallons (2,800 tons) of washing diesel
- Hundreds of pounds of contaminated PPE requiring landfill disposal

   b. **Annual Environmental Impact (425 Tanks)**

The table below summarizes the estimated annual environmental impact from inspecting 425 tanks of various sizes, along with the potential 20% reduction achievable by adopting the 5th edition of API Standard 653.

Waste Stream	Current Impact	Potential 20% Reduction
VOCs from Venting (tons)	1,552	310
GHGs from Vapor Destruction (tons CO_2	11,085	2,217
Construction Emissions (tons CO_2e)	55,427	11,085
Crude Sludge (tons)	36,582	7,316
Blast Media (tons)	5,543	1,109
Washing Diesel (tons)	62,078	12,416
Contaminated PPE (lbs)	2,217	443

7. **Standardized Practices**
   Promotes consistency and clarity across operators by providing specific guidance on the application of API Standard 653, incorporating updated references within Standard 653 to ASME and other relevant codes, and offering clearer direction for inspection and repair procedures.

Key Improvements and Clarifications:

- **Hot Tap Nozzles**: Provides clearer guidance on the installation of hot tap nozzles, including expanded Table 9.1 to cover intermediate shell plate thicknesses (e.g., 5/16" and 7/16").
- **Authorization and Repair Requirements**: Clarifies who can authorize repair work, and outlines requirements for tank settlement and welding repairs.
- **Inspection Intervals and RBI Extensions**: Establishes inspection intervals and supports RBI extensions.
- **Mixed Material Tanks**: Addresses inspection and repair procedures for tanks constructed with mixed materials (e.g., carbon steel, duplex stainless, and austenitic stainless steel).
- **NDE and Damage Mechanisms**: Updates Non-Destructive Examination (NDE) requirements in Annex F and adds references to API 571 for damage mechanisms.
- **Repair Methods**: Confirms that traditional weld overlay and welded bottom patch plates are the only permitted methods for restoring corroded bottom thickness.
- **Definitions and Terminology**: Adds definitions for corrosion allowance, nominal thickness, and allowable tank settlement.
- **Weld Identification and Testing**: Specifies which tank welds require welder identification records and outlines Magnetic Particle Testing (MT) requirements for blend-ground welds.
- **Hydrostatic Testing**: Introduces exemptions for hydrostatic testing after bottom replacements in tanks with known toughness, reducing personnel risk during testing.
- **Settlement Assessment**: Allows two methodologies for assessing out-of-plane tank settlement, replacing the single cosine model from the 3rd Edition. The alternate method in B.2.2.5.2 is now commonly used.
- **Reinforcing Pad Details**: Adds new reinforcing pad options for floor replacement, enabling less extensive welding on existing tanks.
- **Inspection Reporting**: Enhances reporting requirements for tank bottom corrosion and patch plate thickness.
- **Examiner Qualifications**: Introduces qualification requirements for personnel performing ultrasonic thickness measurements.
  Additionally, the 5th Edition addresses recommendations from the Chemical Safety Board following the Motiva Enterprises sulfuric acid tank explosion.[145]

Annex A summarizes the changes between the 3rd and proposed 5th editions of API Standard 653 (with Addendums 1–3).

8. **Modernized Techniques**

Incorporates proven technologies and analytical methods to improve inspection and repair quality.

[145] U.S. Chemical Safety and Hazard Investigation Board, Final Report, Refinery Incident, Motiva Enterprises, LLC, REPORT NO. 2001-05-I-DE (OCTOBER 2002), *available at:* https://www.csb.gov/file.aspx?DocumentId=5608

Since 2008, several technological advancements have been integrated into API 653 to enhance inspection and repair practices. Some of them are:

- **Out-of-Plane Settlement Evaluation**: A new methodology has been introduced for evaluating out-of-plane settlement, offering greater flexibility and accuracy, especially when used with modern data collection methods like 3D laser scanning.
- **Advanced Weld Inspection**: Alternating Current Field Measurement (ACFM) is now used to inspect existing welds that are closer together than permitted by API 650, improving safety and reliability.
- **In-Service Repairs**: Friction stud welding has been incorporated to enable tank retrofits and repairs while the tank remains in service, minimizing downtime while ensuring safety.
- **Non-Metallic Repairs**: Clause 9.4 of the 5th Edition allows the use of non-metallic materials for shell plate repairs, reducing the need for hot work on operating tanks.
- **Ultrasonic Inspection for Insulated Tanks**: Pulsed echo ultrasonic inspection is particularly effective for assessing insulated tank roofs. This method addresses the risk of roof corrosion and potential structural failure—factors not adequately captured by traditional time-based inspection approaches.
- **3D Laser Scanning for Settlement Analysis**: More accurate settlement data obtained via 3D laser scanning often reveals deviations from the cosine tilt model in Annex B. The 5th Edition accommodates this with more flexible analysis options.

9. Addressing Past PHMSA Concerns

In 2015, PHMSA revised Sec. 195.432 to no longer allow operators to utilize RBI.[146] At the time, PHMSA raised concerns that the RBI procedures did not require "adequate or consistent assessment factors for establishing an alternative internal inspection interval."[147] Specifically, PHMSA noted that certain assessment considerations were not mandatory, that the procedures allowed operators to establish a minimum bottom plate thickness less than minimum values referenced elsewhere in API Std. 653, and that, in general, PHMSA did not agree with inspection intervals exceeding 20 years.[148]

Removal of the RBI alternative was not well supported on technical, safety, or economic grounds. When PHMSA removed the RBI alternative, the agency did not perform a risk assessment to analyze the cost, benefits, or an evaluation of other options PHMSA considered as required by the Pipeline Safety Act.[149] Instead, as part of an IBR rulemaking (which did not incorporate a new

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[146] Pipeline Safety: Periodic Updates of Regulatory References to Technical Standards and Miscellaneous Amendments, 80 Fed. Reg. 168, 172 (Jan. 5, 2015).

[147] *Id.* at 171.

[148] *Id.*

[149] 49 U.S.C. § 60102(b)(2)(D)-(E), (b)(3).

version of API Std 653) the agency made the conclusory statement that it "estimates the costs of incorporating these standards to be negligible and the net benefits to be high."[150] Therefore, PHMSA never provided a thorough analysis to justify the agency's position. The Associations contend that the information provided above demonstrates the RBI will couple a high margin of safety with an efficient allocation of resources.

Additionally, the tank safeguard incentives, the clear guidance provided by the latest edition of the API Standard 653 to define inspection intervals based on sound engineering practices, and updated references to other codes address the concerns PHMSA raised in the 2015 rulemaking. For all the reasons mentioned above, PHMSA's adoption of the 5th edition of API Std 653, including Addendums 1, 2, and 3 in its entirety and without exceptions, would represent a significant step forward in ensuring the safety, reliability, and environmental stewardship of breakout tank operations.

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[150] 80 Fed. Reg. 176 (Jan. 5, 2015).

Annex A: Agenda Items Incorporated in API Std 653 Since 2008 Edition

4th Edition, April 2009

Agenda Item	Edition with ballot items
653-150	Developed new methodology for evaluating out-of-plane settlement.
653-167	Establishes inspection intervals for initial inspection and extension credits for RBIs.
653-212	Provides alternative details for installing a new bottom through an existing low type nozzle reinforcing plate.
653-221	Allows engineering support of inspection activities to qualify for recertification of tank inspector status.

4th Edition, Addendum 1, August 2010

Agenda Item	Edition with ballot items
653-157	Establishes rules for tanks with missing nameplates or certification
653-185	Dropped the requirement for welded striker pads under aluminum floating roof legs, allowing Teflon spacers if there is no evidence of corrosion damage from such spacers on the previous bottom.
653-211	Adds duplex stainless steels to the allowable materials for storage tank reconstruction.
653-213	Addresses the inspection and repair of mixed material tanks (carbon steel, duplex stainless, and austenitic stainless steel).
653-229	Revise paragraphs 9.9.2.2 and 9.9.4 Note 1 to include a reference to paragraph 11.3 that covers weld repairs techniques in lieu of PWHT to tanks or tank components that were originally post weld heat treated.
653-230	Editorial changes to coordinate language and paragraph structure between Annexes S and X.
653-232	Allows fitness-for-service as an option for existing welds that are not acceptable to the as-built standard.
653-237	Editorial changes to the names of referenced documents and the inclusion of others at the recommendation of the CSB.

4th Edition, Addendum 2, January 2012

Agenda Item	Edition with ballot items
653-195	Provides specific guidance on the installation of door sheets
653-218	Adds visual acuity requirements for visual examinations
653-222	Editorial changes to resolve inconsistent cross-referencing between API 653 and API 650.
653-240	Provides specific guidance on the spacing of fillet welds on tombstone patch plates in the critical zone that will affect a vertical shell seam weld.
653-244	Corrects welding references to clarify that all 653 tanks (not just dismantled and reconstructed tanks) refer to 650 welding requirements.
653-245	Extend initial inspection intervals for the use of safeguards and eliminate arbitrary caps when using RBI for subsequent inspection intervals.

653-246	Allows interpolation within Table 4.5 regarding the need for replacement/repair of annular plates.
653-251	Editorial correction to the description of the dimensions between the telltale hole and the horizontal weld of the reinforcing plate in Figure 9.10.
653-253	Editorial correction to 12.5.1.2, dropping "an even" in front of number of elevation measurement points.

4th Edition, Addendum 2, January 2012

Agenda Item	Edition with ballot items
653-195	Provides specific guidance on the installation of door sheets
653-218	Adds visual acuity requirements for visual examinations
653-222	Editorial changes to resolve inconsistent cross-referencing between API 653 and API 650.
653-240	Provides specific guidance on the spacing of fillet welds on tombstone patch plates in the critical zone that will affect a vertical shell seam weld.
653-244	Corrects welding references to clarify that all 653 tanks (not just dismantled and reconstructed tanks) refer to 650 welding requirements.
653-245	Extend initial inspection intervals for the use of safeguards and eliminate arbitrary caps when using RBI for subsequent inspection intervals.
653-246	Allows interpolation within Table 4.5 regarding the need for replacement/repair of annular plates.

4th Edition, Addendum 3, November 2013

Agenda Item	Edition with ballot items
653-252	Clarifies survey practice during hydrotest of existing tanks.
653-254	Adds guidance on sump installation.
653-255	Editorial - defines and clarifies the use of "examiner" and "inspector".
653-256	Adds guidance on the installation of a new foundation under a tank that does not meet the elevation tolerances of API 650.
653-257	Editorial correction to eliminate duplicated wording at the end of 12.1.2.3.

5th Edition, November 2014

Agenda Item	Edition with ballot items
653-258	Addresses the inspection and repair of mixed material tanks (Annex SC) based on the revisions to the design standard to permit temperature limits greater than 200 degrees F.
653-260	Clarifies acceptance criteria for each of the weld defects described in Section 9.6.
653-261	Eliminates the confusion between sections 12.1.3.2 and 12.2.1 regarding the required number of NDE on a repaired butt weld.
653-262	Allows similar service as an option for determining the initial inspection of a new or refurbished tank in the table of tank safeguards.

653-266	Allows longer initial internal inspection intervals for tanks with stainless steel bottoms.
653-267	Clarifies Annex C inspection checklists regarding insulated roofs, especially regarding water ingress.
653-271	Expands Table 9.1 to include intermediate sizes of 5/16" and 7/16" thick shell plate for hot tap nozzles.
653-272	Editorial - changed title of API 2016 to a recommended practice.
653-2001	Editorial correction of base metal thickness limitation for controlled deposition welding methods
653-2003	Updates NDE requirements summary in Annex F with recent changes and revisions in the standard and a changed format to tables.

5th Edition, Addendum 1, April 2018

Agenda Item	**Edition with ballot items**
653-239	Editorial - adds reference to API 650 in hydrostatic testing sections
653-265	Eliminates the word refurbished and defines inspection interval for tank with a new bottom
653-273	Clarifying weld spacing rules when repairs or modifications are made to penetrations
653-275	Provides more detailed instructions on testing required for welding on a tank when the original materials of construction are not known.
653-1001	Revise notes on Figure 9.14 to clarify acceptable alternate repad shapes and to ensure that low type repads and repads that cross butt-welded shell seams are not utilized.
653-2004	Change 9.8.6 to make it consistent with 9.14.1.1 regarding installation of a 4" repad nozzle.
653-2005	Provides a base criterion for evaluating common existing weld conditions and clarifies examination requirements for surface defects on butt welds.
653-2008	Allows the use of ACFM (Alternating Current Field Measurement) to inspect existing welds that are closer than allowed in API 650.
653-2009	Clarify the term "diameter of the penetration" in Section 9.8.6(a).
653-2010	Provides qualification requirements for examiners performing ultrasonic thickness measurements.
653-2011	Clarifies Figure 9.13 to match wording in the code.
653-2013	Define the terms and differentiate between insert plate and thickened insert plate.
653-2014	Clarify the temperatures desired in the description "warm to the hand."
653-2015	Updates Table 4.1 to reflect the change in tensile strength of CSA G40.21 steel.
653-2016	Allows the use of ultrasonic examination in lieu of radiographic examinations.
653-2017	Clarify Annex B criteria for settlement measurements on repaired/replaced bottoms
653-2022	Clarify MT/PT requirements for new attachments to the shell plate under API 653 to be consistent with those for new tanks in API 650.

5th Edition, Addendum 2, May 2020

Agenda Item	Edition with ballot items
653-1005	Add provisions in 9.2.4 for (temporary) door sheet stiffening.
653-2002	Establish procedures for installing hot tap nozzles on tanks with shell plate materials that would previously dictate emptying and cleaning a tank to perform the required thermal stress relief.
653-2018	Clarify the intent of Table 6.1 regarding release prevention barriers.
653-2020	Clarify within the standard which tank welds require welder identification records.
653-2025	Clarify the application of API Group IV and higher material requirements when the existing material is unknown.
653-2026	Allow repairs to be made from nonmetallic composite materials.
653-2028	Add "Unless a stress analysis is performed" to paragraph 4.4.5.7 regarding the evaluation of the thickness of the bottom edge projection.
653-2033	Add a definition for "inspection activities as described in API 653" for its use in Annex D.
653-2034	Editorial correction to clarify that shell welds for reinforcing plates require an ultrasonic examination in addition to MT or PT testing.
653-2036	Clarify that all new shell seams created using Figure 9.9 (Method for Raising Shell Nozzles) must comply with Figure 9.1.

5th Edition, Addendum 3, November 2023

Agenda Item	Edition with ballot items
653-1002	Specifies the tank bottom patch plate thickness.
653-1004	Clarify allowable tank settlement requirements
653-1006	Clarify the location of horizontal weld seam on new reinforcing plates (half pads).
653-1007	Correcting Annex references in Table 4.2 (joint efficiencies for welded joints)
653-1008	Establish a corrosion allowance definition.
653-1011	Establish a nominal thickness definition.
653-2020	Clarification of MT requirements for blend-ground length of welds if a hydrotest has not been planned.
653-2021	Clarify cross-reference on welding to existing shell HAZ in reconstructed tanks.
653-2023	Provide clearer guidance for required thickness in the critical zone.
653-2031	Improve inspection reporting on tank bottom corrosion.
653-2035	Provide clarification on who can authorize repair work.
653-2037	Allow for short term deferral of out-of-service API 653 internal inspection if certain criteria are met.
653-2040	Update Table 6.1 to clarify credit for unreinforced thick -film linings.
653-2043	Requirements to exempt hydrostatic tests after bottom replacements for tanks with known toughness.

653-2044	Include "friction stud welding" in API 653 to allow tank retrofits and repairs to be made using friction stud welding in accordance with ASME Section IX.
653-2046	Allow for short term deferral of out-of-service API 653 inspection based on an alternate technical approach (follow up on agenda Item 653-2037).
653-2047	Add references to API 571 - Damage Mechanisms.
653-2048	Addresses CSB recommendations issued after Motive Enterprises sulfuric acid tank explosion.
653-2049	Allow for short term deferral of out-of-service API 653 inspection based on an alternate technical approach (follow up on agenda Items 653-2037 and 653-2046).
653-2050	Clarify verbiage for removing a coating on an area to be welded.
653-2052	Clarify that traditional methods of weld overlay and welded bottom patch plates are the only permitted repair methods to restore bottom thickness after bottom corrosion.