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

Pipeline Safety: Class Location Change Requirements	Docket No. PHMSA-2017-0151

COMMENTS IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

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

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I. Introduction

The American Gas Association (AGA),[1] American Petroleum Institute (API),[2] American Public Gas Association (APGA),[3] GPA Midstream Association,[4] Interstate Natural Gas Association of America (INGAA),[5] and NACE International Institute[6] (jointly "the Associations") submit these comments for consideration by the Pipeline and Hazardous Materials Safety Administration (PHMSA) regarding the Agency's Notice of Proposed Rulemaking, "Pipeline Safety: Class Location Change Requirements" ("Proposed Rule" or "NPRM").[7] Pipeline safety is the top priority of the Associations and our members, including minimizing releases of natural gas. The Associations strongly support regulations that advance improvements in pipeline safety practices and that embrace modern integrity management processes and technologies, with the intent of continuously improving the safety and reliability record for our nation's natural gas pipeline network.

The Associations generally support PHMSA's proposal to modernize the class location change regulations to provide an integrity management-based option for addressing class changes on gas transmission

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

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

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

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

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

[6] The NACE Institute focuses on meeting industry needs for workforce certification programs, pursuing global consistency of certification requirements, raising industry and public awareness of the purpose and benefits of certification programs, and supporting employment of certified corrosion control professionals. The NACE Institute administers 23 certifications on such disciplines as cathodic protection, general corrosion, general coatings, pipeline, specialty credentials and the industry-leading CIP (Coatings Inspector Program) certification.

[7] Pipeline Safety: Class Location Change Requirements, 85 Fed. Reg. 65,142 (Oct. 14, 2020) [HEREINAFTER, *NPRM*].

pipelines.[8] This rulemaking aligns with PHMSA's history of providing risk-based options for managing pipeline safety when risk-based controls have been demonstrated to be effective. The class location change regulations have not been substantively updated in fifty years. These regulations are obsolete and currently hinder operators from investing in more modern approaches that enhance safety, ensure reliability, and minimize emissions. Furthermore, the Proposed Rule aligns with the management system and continuous improvement principles embodied in pipeline safety management systems (PSMS). Advancing the implementation of PSMS is a shared goal of operators, PHMSA, and public stakeholders.

In the comments below, the Associations recommend specific changes to the Proposed Rule to ensure that the new integrity management alternative for managing class location changes fully embraces the safety, reliability, and environmental opportunities presented by this rulemaking. The Associations' comments are also intended to ensure that PHMSA's final rule provides clear requirements and leads to an efficient use of pipeline operators' resources. Finally, the Associations' comments are intended to demonstrate to public stakeholders that our support for this rulemaking is driven by our members' commitment to achieve the highest level of safety, reliability, and environmental performance. The Associations are confident that the Proposed Rule will help advance those shared goals. The Associations remain committed to ongoing evaluation, continuous improvement, and transparency regarding pipeline risk management strategies that enables stakeholders to effectively engage with operators and PHMSA on pipeline safety topics.

II. The Associations Strongly Support PHMSA's Proposal to Add an Integrity Management Option for Managing Class Location Changes

The purpose of the class location change regulations is to ensure an appropriate safety margin when population growth occurs around an existing pipeline, and this remains unchanged from when the rules first were adopted in 1970. However, this objective can now be accomplished using modern integrity management programs, which are a more effective, efficient, environmentally sound and less disruptive means of managing pipeline safety than the class change pipe replacements and pressure reductions often required under current § 192.611. Many stakeholders—including pipeline operators and service providers, PHMSA and state regulators, the National Transportation Safety Board, and public advocacy groups—have worked to develop, implement, and enhance integrity management programs over the last several decades. It is because of today's integrity management processes and technologies that class location changes no longer present the risk that they may have in the past. Furthermore, deploying integrity management programs is essential to implementing PSMS because integrity management programs provide pipeline integrity information and risk insights that enable the continuous improvement framework imbedded in PSMS.

The Associations strongly support PHMSA's proposal to add an integrity management option for managing class location changes. Below is the Associations' perspective on the benefits of the new option proposed by PHMSA.

[8] The Associations' positions articulated throughout these comments are specific to gas transmission pipelines. They should not be applied to gas distribution, gas gathering, or hazardous liquid pipelines.

A. The integrity management option will improve safety.

Revising the antiquated class location change requirements to allow a modern integrity management option is long overdue. The tremendous energy and resources that operators, state and federal regulators, and public representatives have invested in developing, implementing, and enhancing integrity management programs over the last two decades is indicative of the value of these programs in ensuring pipeline safety, whether or not a class location change has occurred. It is no coincidence that new gas transmission pipeline safety rulemakings for the last two decades have focused on implementing integrity management programs—not pipe replacements or permanent pressure reductions, which is a focus of current § 192.611.

The new integrity management option for managing class location changes will dramatically enhance gas transmission pipeline safety. For many operators that frequently experience class location changes, the new integrity management option will unlock an enormous pool of pipeline safety resources that are currently allocated towards low-value pipe replacements. This will allow operators to refocus those resources towards modern technologies that provide better information about the overall safety of the pipeline and more opportunities for beneficial pipeline safety interventions. The Associations estimate that gas transmission pipeline operators spend $200–$300 million annually to replace pipe solely to satisfy the current class location change regulations.[9] Despite these huge annual costs, less than 75 miles of pipe are replaced each year (less than .05% of the gas transmission pipeline network). These inordinate total pipe replacement costs are incurred because the current class location change regulations often require inefficient replacements of small segments of pipe. Such short replacements provide minimal safety benefits, particularly since most of the replaced pipe was in safe, operable condition prior to the replacement. This Proposed Rule presents the opportunity to reallocate these significant resources away from low-value, short pipe replacements and instead towards technologies and processes that will do more to enhance the safety of the entire pipeline system, beyond just the short segment where the class change occurred.

As examples of the potential safety benefits of a integrity management option for managing class location changes, for $250 million, instead of replacing less than 75 miles of pipe, operators could assess over 25,000 miles with in-line inspection,[10] install launchers and receivers to enable over 5,000 miles of pipeline to be assessed with in-line inspection tools for the first time,[11] or conduct over 4,000 anomaly evaluation digs.[12] Such assessments allow operators to identify pipeline segments that actually warrant remediation or replacement because of an identified anomaly, rather than the current § 192.611 requirements that lead to pipe replacements regardless of pipe condition. These examples illustrate how investment in, and

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[9] Comments of AGA, API, APGA, and INGAA on Pipeline Safety: Class Location Change Requirements at 43–44, No. PHMSA-2017-0151-0002 (Oct. 1, 2018), https://beta.regulations.gov/comment/PHMSA-2017-0151-0018 [HEREINAFTER, *Associations ANPRM Comments*].

[10] Although in-line inspection costs will vary substantially based on the type of tool and other operational factors, data from the Associations' member survey indicates an average cost of $10,000 per mile for in-line inspection.

[11] Although the costs of installing launchers and receivers will vary significantly based on pipeline-specific factors, data from the Associations' member survey indicates an average cost of $1.8 million to install a mid-diameter (16-24 in.) launcher and receiver set.

[12] Although the costs of an anomaly evaluation dig will vary substantially based on the specific circumstances of the excavation, data from the Associations' member survey indicates an average cost of $62,500 to conduct an anomaly evaluation dig.

utilization of, modern integrity management programs can enhance pipeline safety following a class location change in a more effective, efficient, and sustainable manner than allowed by the current class location regulations. Integrity assessments provide significantly more information and data about the pipeline system than replacing short pipe segments. Therefore, integrity management offers substantial benefits for managing overall pipeline system integrity.

Natural gas pipeline transportation is economically regulated such that rates are set based upon a fixed level of costs.[13] Therefore, higher-cost, lower-value requirements, such as the existing class location change regulations, can siphon resources away from investing in and using more effective modern technologies and processes, such as integrity assessments. Although operators often voluntarily conduct integrity assessment program activities, resources will always be prioritized to meet mandatory requirements.[14]

The Research and Special Programs Administration (PHMSA's predecessor) completed the first rulemaking to require integrity management programs for gas transmission pipelines in high consequence areas in 2003.[15] At that time, the Agency stated that "[t]he [Integrity Management] rule will provide a better technical justification to support waivers from existing requirements that mandate replacement of pipeline when population increases cause a change in class location. Experience may lead to future changes in the existing requirements."[16] There has now been almost fifteen years' experience to use as a basis for determining how best to harmonize class location changes with integrity management programs. During that time, PHMSA has employed its special permit process to pilot test integrity management options for managing class location changes. This pilot program has proven incredibly successful. PHMSA notes in the NPRM that "to date, no leaks or failures have occurred on the approximately 100 miles of current class location change special permit pipeline segments."[17]

Proposed § 192.618 reflects the requirements of PHMSA's recent final rule on "Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments"[18] and the anticipated requirements of PHMSA's pending final rule on "Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments." Thus, § 192.618 will both maximize the benefits of those rules and encourage early adoption of them. During prior public proceedings that

[13] Rates for natural gas pipelines are regulated by the Federal Energy Regulatory Commission (interstate pipelines), state public utility commissions (intrastate pipelines), or the local governing body that oversees a public system.

[14] Increasing rates to recover increased costs associated with voluntarily investing in and utilizing new technologies and processes is not always a viable option. For example, the highly competitive marketplace in which interstate gas transmission companies operate often does not allow pipelines to charge customers increased rates, even in cases where the Federal Energy Regulatory Commission has approved the increased rates. Pipeline customers with the ability to switch to other interstate pipelines or other fuels will negotiate a discount with their pipeline, effectually negating the rate increase. A pipeline is then compelled to choose between under-recovering its costs or filing another rate case to further increase its rates in order to be able to reallocate costs among its remaining customers. This further rate increase cycle naturally causes additional customer attrition.

[15] Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines), 68 Fed. Reg. 69,778 (Dec. 15, 2003).

[16] *Id.* at 69,782.

[17] *NPRM* at 65,148.

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

considered updating the class location change regulations, public safety advocacy groups suggested that, in advance of an update to the class location change requirements, PHMSA should first refine and expand integrity management programs.[19] The aforementioned two rulemakings did or will enhance and broaden integrity management programs, and those new integrity management program requirements are reflected in proposed § 192.618.

Furthermore, the in-line inspection requirements in § 192.618 will spur further deployment of modern inspection technologies, promote continuous improvement of those tools, and incentivize operators to modify more pipeline segments to allow for in-line inspection. For example, as more segments of pipeline are reassessed with ILI tools, run on run comparisons allow for a more precise understanding of pipeline condition and provide better estimates of anomaly growth rates. As another example, EMAT ILI tools have emerged as a premier, commercially viable assessment method for crack-like defects affecting gas transmission pipelines. Proposed § 192.618 will promote increase deployment, improvement, and cost-effectiveness of EMAT technology.

B. A third-party assessment has demonstrated that PHMSA's proposed integrity management option will enhance safety.

INGAA commissioned Blade Energy Partners to conduct a third-party assessment of the safety benefits of proposed § 192.618.[20] Blade performed a quantitative assessment of the probability of failure for a class 1 to 3 change segment and a surrounding class 1 inspection area due to the threats of corrosion and SCC. Blade concluded that the ILI assessment and anomaly response requirements of proposed § 192.618 would "deliver robust pipeline reliability for the time-dependent Corrosion and SCC threats . . . that is in excess of that required by many structural reliability codes."

The Blade Report includes a case study of the application of proposed § 192.618 based on ILI data from an actual 25,000-ft pipeline segment where two sections of the segment have experienced a class 1 to 3 change, and the remainder of the segment is in class 1 locations. For the class 1 to 3 changes managed in accordance with § 192.618 on this example segment, Blade determined that the probability of failure due to a corrosion anomaly during the seven-year assessment interval would be $1x10^{-7}$ or less. For comparison, this is equivalent to the probability of failure targeted by AFCEN for French nuclear installations, which is $1x10^{-7}$. Similarly, for class 1 to 3 changes managed in accordance with § 192.618, Blade determined that the probability of failure due to SCC during the seven-year assessment interval would never exceed $1x10^{-5}$ during the assessment interval, following initial immediate repairs. For comparison, this is consistent with the probability of failure targeted by the American Association of State Highway and Transportation Officials for bridge beam designs, which is between $1x10^{-4}$ and $1x10^{-5}$, and the probably of failure targeted by Canadian Standard CSA Z662 for oil and gas pipeline systems, which is $1x10^{-4}$ per km/yr.

Furthermore, the Blade Report demonstrates the safety benefits of § 192.618 in the inspection area outside of the class change segment. Blade concludes that "[f]or Class 1 locations within the vicinity of

[19] See presentations from Pipeline Safety Trust and Accufacts, Inc. during PHMSA Class Location Methodology Public Workshop (Apr. 16, 2014). http://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=95.
[20] BLADE ENERGY PARTNERS, RELIABILITY-BASED APPROACH TO ASSESS TREATMENT OF CORROSION AND SCC THREATS FOR PIPELINE CLASS LOCATION CHANGES (2020) [HEREINAFTER, *Blade Report*] (the Associations submit the Blade Summary Report as part of these comments).

Class location changes, the PHMSA guidelines [§ 192.618] still deliver strong reliability for the Corrosion and SCC threats analyzed . . . ." For this example segment, which is an actual segment, if the operator replaced the class 1 to 3 segment in accordance with current § 192.611 and never inspected the adjacent class 1 segments, numerous anomalies could have grown to potential failure (predicted failure pressure less than MAOP) during the seven-year assessment interval. Without the application of § 192.618, it may be many years before an integrity assessment (such as an ILI run) occurs in this class 1 inspection area because PHMSA's regulations do not require integrity assessments for class 1 locations that are not in an MCA or an HCA. [21]

Figure 1 below shows the probability of failure and safety factor for corrosion anomalies identified on this pipeline segment at year zero. The areas highlighted in yellow are class 1 to 3 change segments, and all other areas are class 1 locations. Each of the black dots is a potential anomaly identified by ILI. The blue boxes show anomalies for which the predicted failure pressure is below 1.1xMAOP at year zero, and numerous other anomalies are shown that could grow to have safety factors below 1.1xMAOP during the assessment interval. Figure 1 demonstrates that applying § 192.618 in year zero would prevent numerous anomalies in class 1 locations from growing to failure by year seven. Replacing the class change segments (yellow highlighted areas) with anomaly-free pipe provides no similar benefit for the class 1 segments in the inspection area (non-highlighted areas).

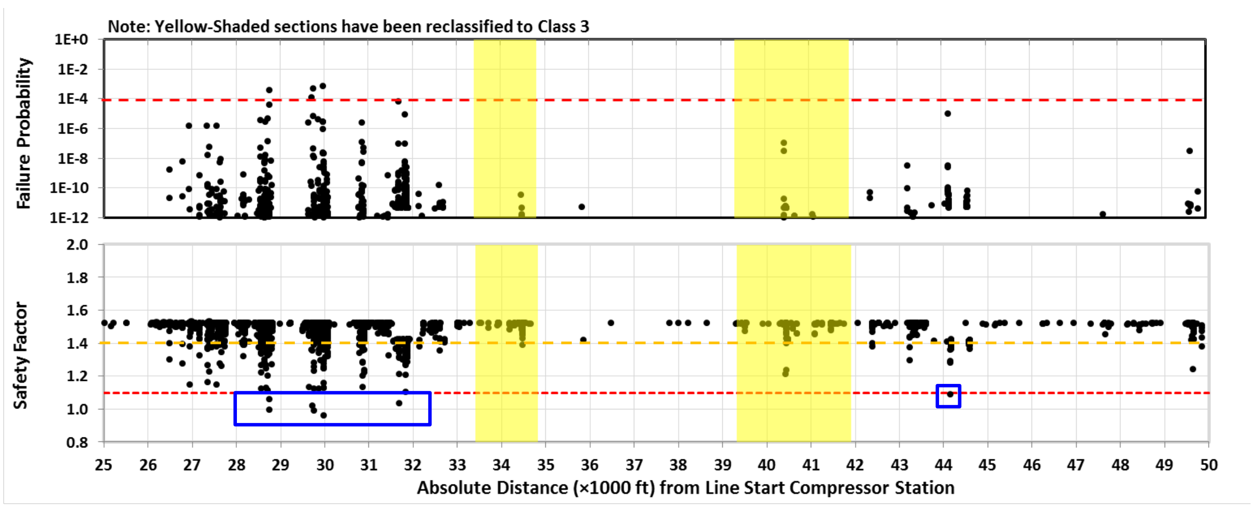

Figure 1. Probability of failure and safety factor results for corrosion anomalies on example segment, year zero.

For corrosion anomalies, applying proposed § 192.618 in the class 1 inspection area for this example segment would keep the probably of failure due to a corrosion anomaly to less than $1x10^{-4}$. For comparison, this is consistent with the probability of failure targeted by the American Association of State Highway and Transportation Officials for bridge beam designs, which is between $1x10^{-4}$ and $1x10^{-5}$, and the probably of failure targeted by Canadian Standard CSA Z662 for oil and gas pipeline systems, which is $1x10^{-4}$ per km/yr.

For SCC anomalies, the Blade Report also indicates that proposed § 192.618 provides significant benefits in ensuring safety in the inspection area, compared to a § 192.611 pipe replacement. For this example

[21] In reality, the operator of this segment had completed multiple ILI runs on this segment and addressed anomalies.

pipeline segment, applying proposed § 192.618 would keep the probably of failure due to SCC anomalies in the class 1 portion of the in-line inspection area less than $1x10^{-4}$, and the probability of failure drops precipitously after scheduled anomalies are addressed early in the assessment interval. Figure 2 below shows the higher safety factor and lower probability of failure for SCC anomalies provided in the Class 1 inspection area with § 192.618 applied, compared to a scenario where there were "no repairs" in the Class 1 inspection area (because the Class 1 to 3 segment was replaced under current § 192.611 and no ILI assessment was required in the Class 1 inspection area). Note that the safety benefits are significant for both § 192.618 as proposed by PHMSA and with the revisions recommended by the Associations in Section V.D below (the data for the Associations' proposal was labeled as "INGAA" by Blade in Figure 2 below).

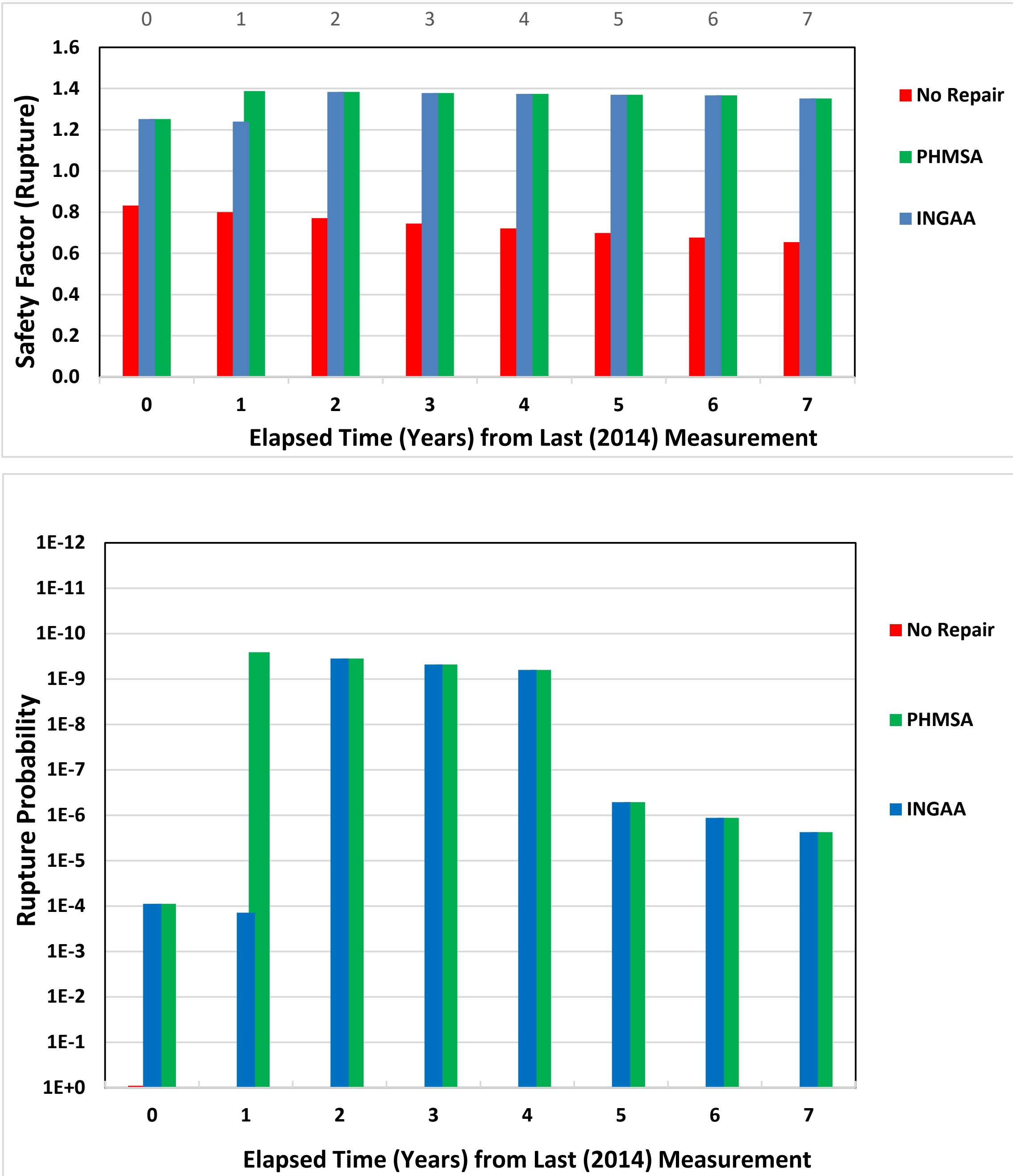

Figure 2. Probability of failure and safety factor results for SCC in the Class 1 inspection area on the example segment where § 192.618 integrity management is applied ("PHMSA") compared to class change pipe replacement ("no repair").

C. The integrity management option will reduce emissions.

The environmental benefits of applying integrity management requirements instead of replacing safe, operable pipe are as compelling as the safety benefits. The pipe replacements that are often required to address class changes under existing § 192.611 can necessitate "blowing down" natural gas to the atmosphere so that the replacement project can safely proceed. The Associations estimate that class change pipe replacements under the current regulations result in up to 800 million standard cubic feet of natural gas blowdowns to the atmosphere each year, which would be substantially reduced under proposed § 192.618.[22] This volume of natural gas (800 million standard cubic feet) could meet the needs of over 10,000 homes for a year[23] and has the same greenhouse gas reduction benefits of removing 80,000 cars from the road.

When feasible, operators may implement blowdown mitigation measures to reduce the volume of natural gas released. The Associations estimate that class location change pipe replacements would still result in up to 300 million standard cubic feet of natural gas blowdowns annually, if mitigation measures are consistently implemented.[24] Therefore, even with mitigation measures in place, PHMSA's proposed integrity management option for managing class location changes would significantly reduce the volume of natural gas released to the atmosphere.

D. The integrity management option will reduce community and consumer impacts.

The construction activities necessitated by class change pipe replacements can restrict deliveries to consumers and cause unnecessary construction disturbances in communities. No natural gas can travel through a pipeline during a pipe replacement, and class change pipe replacements can require significant construction activities that local communities would prefer to avoid. Unlike current § 192.611, which often requires pipe replacements regardless of pipe condition, PHMSA's proposed § 192.618 would only require a pipe replacement where integrity assessments indicate that such a replacement is necessary for safety—lessening the impact on communities and customers while continuing to ensure safety.

Decreasing the MAOP on a gas transmission line to comply with § 192.611 after a class location change often is not an acceptable solution for local gas distribution companies (LDCs). LDCs, which contract with gas transmission pipelines to transport natural gas to their city gate stations, have an obligation to serve their residential and commercial customers reliably. LDCs, like other pipeline customers, need to transport their full contractual amounts during peak demand periods. Shutting down a pipeline to perform a replacement creates similar, albeit temporary, challenges. The Associations note that 95% of publicly-owned gas systems receive their natural gas from a single transmission pipeline. If that transmission pipeline cannot maintain pressure or service, there is an increased risk that the gas transmission company will not be able to meet its full contractual obligations, threatening a loss or reduction in service to end use consumers.

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[22] This calculation assumes that 886 MCF of natural gas will be released per mile of pipe blowdown and that 5 miles of transmission line must be blown down for each class location change pipe replacement, to account for valve spacing around the class change segment. *See* Process Performance Improvement Consultants, Analysis of Natural Gas Transmission Pipeline Releases and Mitigation Options for Pipeline MAOP Reconfirmation (Mar. 2017), http://www.ingaa.org/?id=35003. The Associations estimate that 185 separate segments are replaced each year due to class location changes. *See* Associations ANPRM Comments at 9 n.26.

[23] *See* American Gas Association's *What Is Natural Gas?*, https://www.aga.org/natural-gas/energy-education/ (last visited Oct. 29, 2020) ("Ten therms of natural gas is about enough to meet the natural gas needs of an average home — space heating, water heating, cooking, etc. — for five days."). Ten therms is roughly equivalent to one thousand standard cubic feet of natural gas.

[24] This calculation assumes that an average of 36% of the natural gas blow down volume will not be mitigated due to limitations in the available mitigation methods and impracticability of applying certain methods to certain pipeline systems. *See* Process Performance Improvement Consultants, Analysis of Natural Gas Transmission Pipeline Releases and Mitigation Options for Pipeline MAOP Reconfirmation (Mar. 2017), http://www.ingaa.org/?id=35003.

E. The integrity management option provides an improvement to the special permit process.

PHMSA's special permit process has successfully provided a forum for operators and PHMSA to develop and demonstrate the effectiveness of integrity management technologies and processes for managing class location changes. However, the special permit process is not an appropriate industry-wide or long-term solution. PHMSA and pipeline operators have gained confidence in integrity management technologies and processes over the last two decades. Codifying an integrity management option for class changes in § 192.618 through a deliberative rulemaking process and consistent, nationwide implementation provides more certainty for operators, PHMSA, and the public.

There are numerous challenges with the current special permit process. The timeframe for receiving a special permit approval continues to increase with some special permits taking years from the filing of the application to issuance of the permit.[25] Operators file special permit applications based on PHMSA's published "typical conditions,"[26] yet, in recent years, PHMSA has imposed additional requirements. This practice creates significant uncertainty for operators when assessing whether to invest the substantial resources required to draft a special permit application.

The special permit renewal process also presents significant uncertainty for pipeline operators. An operator decides to file for a special permit based on an understanding of the typical special permit requirements in effect at the time of submittal, which include requirements to complete significant pipeline integrity work. During the permit renewal process, PHMSA has the option to increase the requirements significantly, resulting in an additional burden that the operator would not have known when it submitted the original special permit request. Yet, the operator has "sunk cost" invested in the original work completed under the initial special permit. Had the operator known of the future obligations that would be imposed during renewal, the operator may have elected not to file for the special permit in the first place.

These challenges are underscored by the fact that several class location change special permits have not been renewed in recent years. Instead of continuing with the overly-burdensome special permit process and taking the risk that PHMSA might change the requirements in the future, operators have elected to replace these pipe segments. The integrity management programs implemented on those special permit segments may have been scaled back or discontinued so that the resources could be reallocated to meet other regulatory requirements, such as pipe replacements for other class change segments.

Finally, the level of resources required to complete the administrative work associated with the special permit process often compel operators to proceed with construction activities to replace pipe that is in safe, operable condition. Differing special permit requirements can result in inconsistent interpretation and application by PHMSA personnel. Proceeding with proposed section 192.618 would provide more clarity, consistency, and alignment with other existing regulations.

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[25] Duke Energy Gas Transmission, Waiver Request, PHMSA-2007-27122, https://www.regulations.gov/docket?D=PHMSA-2007-27122. The application was filed on October 10, 2006 and approved on September 23, 2009 (Duke Energy Gas Transmission changed its name to Spectra Energy Transmission in 2007).

[26] PHMSA, *Example Class Location Special Permit Typical Conditions* (Sept. 1, 2012), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/class-location-special-permits/64146/specialpermitexampleclasslocspconditions090112draft1.pdf.

F. Pipeline integrity inspection capabilities have dramatically improved over the last several decades, supporting an update to the class location change regulations.

ILI tools that were not yet available when the class location change requirements were first established in 1970 have revolutionized pipeline inspections. Early ILI tools used magnetic flux technology that could only identify metal loss in the bottom quarter of the pipe. Rapid improvement began in the 1980s and continues through today. Technology advancements include improvements in tool sensitivity and detection limits, anomaly sizing accuracy, and differentiation between anomaly types. While ILI technology was initially directed at detecting metal loss and dents, improvements in technology from 1980 to 2000 included sensors and analysis methods to address cracks and improve the resolution for metal loss and dent indications. Improvements in data storage capability allowed ILI service providers and operators to conduct sophisticated analyses in ways that were not possible in the past. In the early 2000s, ILI providers advanced the application of electro-magnetic acoustical transducer (EMAT) technology. Today that technology is being applied to identify and characterize stress corrosion cracking. Currently, ILI providers have begun to combine technologies into single "combo" tools to enable detection of a variety of anomalies in one run.[27] ILI tools are utilizing faster processors and have increased battery life, allowing longer tool runs at higher resolutions to collect more and better data. Processing of data is being continuously improved.

Although many integrity assessment programs utilize internal inspection, other effective assessment methods (pressure testing, guided wave inspection, direct assessment etc.) are successfully applied for threats, anomaly types, or operational circumstances for which internal inspection is not a preferred or practicable solution. The effectiveness of these assessment methods has also advanced as computing technology has expanded engineering, data management, and processing capabilities over the last several decades.

III. PHMSA Should Allow Operators to Apply § 192.618 to Prior Class Location Changes and to Class 2 to Class 3 Changes

To maximize the safety, environmental, and reliability benefits of § 192.618, PHMSA should allow operators to apply this new option to class location changes for which the operator previously implemented a pressure reduction in accordance with § 192.611 or received a special permit prior to the effective date of the final rule. Similarly, PHMSA should also allow operators to apply § 192.618 to class 2 to class 3 changes.

A. PHMSA should expand the applicability of § 192.618 to prior class location changes.

In § 192.618(a)(1), PHMSA proposes to restrict the use of the new integrity management option for managing class changes to class changes that occur after the effective date of the final rule. This limitation restricts the benefits of § 192.618, and PHMSA does not explain the basis for this restriction in the NPRM.

For a class change segment where the operator previously implemented a pressure reduction to comply with § 192.611, PHMSA should allow operators to deploy the § 192.618 program to restore the prior MAOP, in accordance with § 192.618(a)(4)(iv) and Subpart K. Deploying § 192.618 would provide

[27] INGAA, Response to NTSB recommendation: Historical and Future Development of Advanced In-line Inspection (ILI) Platforms for Natural Gas Transmission Pipelines (Apr. 2012), http://www.ingaa.org/File.aspx?id=19697.

significant safety benefits by generating a large amount of new information about the pipeline's condition. This would also benefit pipeline customers because restoring the prior MAOP would safely unlocking capacity on an existing pipeline without the requirement for any new construction.

Similarly, allowing operators to apply § 192.618 to prior class changes allows for withdrawal of existing special permits for class change segments that comply with the requirements of § 192.618. For existing special permit segments that meet § 192.618 criteria, there is no value in requiring operators to continue with the special permit renewal process, which is burdensome for both operators and PHMSA. PHMSA has reported that special permit segments are some of the safest segments in the pipeline network. Requiring similarly-situated pipelines to comply with different operations and maintenance requirements based solely on when a class change occurred is arbitrary.

Restricting § 192.618 to only future class changes is also inappropriate in light of the history of PHMSA's work to update the class change regulations. PHMSA has taken credit for cost savings projected from the use of integrity management in lieu of pipe replacement since the first integrity management rulemaking in 2003, so operators should now be able to realize those benefits through the application of § 192.618 to prior class changes.[28]

B. PHMSA should clarify that restoration of prior MAOP can occur at any time, not only within 24 months of the class change.

In § 192.618(a)(4)(iv), PHMSA proposes an additional 1.39xMAOP test requirement, on top of existing Subpart K uprating requirements, if operators wish to use § 192.618 to restore prior MAOP reductions that were made comply with § 192.611. This provides a high bar that will ensure safety of class change segments at their original MAOP. The Associations support this proposal.

However, the requirements for restoring MAOP in § 192.611(b) and § 192.618(a)(4)(iv) are unclear as currently drafted and could be read to imply that for class changes that occur after the effective date of the final rule, operators must restore the prior MAOP within 24 months of the class change, or else lose their opportunity to ever do so. This does not seem sensible, and it may not be PHMSA's intent, because PHMSA's proposed new text in § 192.611 would provide operators 24 months to *either* implement a pressure reduction or implement § 192.618. It is highly unlikely that an operator would take both of these steps within the initial 24 month period. However, an operator may choose to take a pressure reduction for a few years based on current pipeline capacity demands and then later, if demand increases, implement the § 192.618 requirements to restore the prior MAOP. If a pipeline segment operated at the original MAOP for a number of years and then the operator implements the rigorous requirements of § 192.618 and Subpart K to restore the original MAOP, then there is no new safety risk.

C. A class change segment should not be ineligible for § 192.618 simply because it was in the inspection area for a prior special permit that was denied.

In § 192.618(a)(4)(xi), PHMSA appears to exclude class change segments from § 192.618 if the segment was in the inspection area for a class change special permit application that was previously denied. The focus of special permit applications is the special permit segment—where the class change actually

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[28] *See* Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines), 68 Fed. Reg. 69,778 (Dec. 15, 2003).

occurred—not the in-line inspection area. Presence in the inspection area for a prior special permit application should have no bearing on whether a segment that subsequently experienced a class change is now eligible for § 192.618. Inspection areas often span tens of miles upstream and downstream of special permit segments and could have attributes and histories completely different than the special permit segment. If the class change segment meets the requirements of 192.618, then it should be eligible.

D. PHMSA should allow operators to apply § 192.618 to Class 2 to Class 3 changes.

PHMSA should also allow operators to apply § 192.618 to class 2 to class 3 changes. This is important and beneficial in at least two scenarios.

First, segments with a class 1 design factor that experienced a change to class 2 in prior years and then to class 3 following the effective date of the final rule are no different than segments that jump from class 1 to class 3 all at once. PHMSA's proposal may already be intended to include these segments, but the proposed code language could be interpreted otherwise.

Second, segments with a class 2 design factor are required to have a 1.25xMAOP pressure test under § 192.619. However, § 192.611 currently requires a 1.5xMAOP pressure test in order for a class 2 to class 3 change to continue operating at its original MAOP. Although many operators "over test" class 2 segments today to allow for the one-class bump provided under § 192.611, this has not always been common practice. Allowing § 192.618 to apply to class 2 to class 3 segments would provide such segments a mechanism, other than a pipe replacement, to continue operating at the current MAOP. If § 192.618 is appropriate for pipe with a Class 1 design factor, it should also be appropriate for pipe with the more conservative Class 2 design factor.

IV. PHMSA Should Provide Options for Operators to Manage Certain Pipeline Features

A. PHMSA should require EFW and LF-ERW pipe to be tested for fitness, rather than deeming all vintage seams ineligible.

In § 192.618(a)(4)(vi), PHMSA proposes to exclude all class change segments that have vintage seam types from the integrity management option for managing class location changes. The Associations strongly object to this proposal because it would exclude many good candidates from the § 192.618 program. Not all vintage seams are identical, and operators should be permitted to demonstrate that seams are fit for continued service.

Specifically, the Associations request that PHMSA allow electric flash welded (EFW) and low frequency electric resistance welded (LF-ERW) to be included in § 192.618, with appropriate fitness testing for those pipe seams. Technologies and practices are readily available to manage threats that could be associated with EFW and LF-ERW pipe, and a number of these technologies and practices are incorporated in existing Part 192 requirements. This is evidenced by the fact that many existing class change special permits cover EFW and LF-ERW pipe. Clearly these threats can be safely managed, as PHMSA has reported that no leaks or incidents have occurred on class change special permit segments. The same suite of integrity management practices can also be employed to safely manage other types of vintage pipe, such as pipe with DC-ERW seams, but the Associations focus our comments on EFW and LF-ERW because those are the two most prevalent vintage seam types and therefore represent the biggest opportunity for inclusion in § 192.618.

PHMSA commissioned Battelle to study LF-ERW and EFW threats, and that study produced a series of recommendations regarding how operators can *manage* those threats—the study did not recommend limiting the use or operational parameters of pipe segments with those seam types.[29] Many of the management strategies identified through the Battelle study have since been incorporated into Part 192 and will apply to class changes managed under § 192.618. Aside from the Battelle study, PHMSA has commissioned additional studies which demonstrate that vintage seam threats can be managed, and the recommended management strategies from those studies have been directly referenced in class location change special permits.[30]

For example, manufacturing and construction flaws are generally considered stable if they have been successfully tested to 1.25xMAOP,[31] which is a baseline requirement of proposed § 192.618. Class change segments operated under proposed § 192.618 would also be required to comply with vintage seam threat evaluation and assessment requirements under § 192.917(e). For example, operators must evaluate the threat of cyclic fatigue under § 192.917(e)(2). Cyclic fatigue has caused failures of LF-ERW pipe, but primarily on liquid pipelines, not gas pipelines. The Associations would support excluding from § 192.618 any pipeline segments where the threat of significant cyclic fatigue is present, based on the analysis required under from § 192.917(e)(2).

There is strong evidence that the vintage management strategies described above are working; according to PHMSA data, manufacturing-related failures on onshore gas transmission pipelines have declined precipitously over the past two decades[32]—including an approximately 90% decrease between 2002 and 2017 and a 75% decrease since the PG&E failure in San Bruno in 2010[33]—and such incidents are exceedingly rare on pipelines managed under a Subpart O integrity management program.[34]

Finally, for non-seam threats that may be associated with vintage pipe, additional integrity management methodologies exist to address those threats as would be required under proposed § 192.618(b)(2). For example, pipe body hard spots have been associated with certain EFW pipe. Where the threat of hard spots is present on a class change segment, operators would be required to assess for this threat under proposed § 192.618(b)(2). To comply with this requirement, operators could run a hard spot ILI tool or equivalent assessment method and remediate hard spots that do not meet API 5L requirements.

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[29] *See* Battelle, Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures – Phase One (2013), https://www.aga.org/sites/default/files/sites/default/files/media/phmsa_final_summary_erw_seam_failures_1.pdf.

[30] KIEFNER AND ASSOCIATES, EVALUATING THE STABILITY OF MANUFACTURING AND CONSTRUCTION DEFECTS IN NATURAL GAS PIPELINES (2007); MICHAEL BAKER JR. AND KIEFNER AND ASSOCIATES, ET AL., LOW FREQUENCY ERW AND LAP WELDED LONGITUDINAL SEAM EVALUATION.

[31] *See* 49 C.F.R. § 192.917(e)(3) (2020).

[32] PHMSA, *Significant Incident 20 Year Trend*, https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-20-year-trends (last visited Oct. 18, 2020).

[33] INGAA, *Pipeline Safety & Reliability* (Mar. 5, 2019),https://www.ingaa.org/File.aspx?id=35766&v=dd93d836.

[34] PHMSA, *GT IM Performance Measures*, https://www.phmsa.dot.gov/pipeline/gas-transmission-integrity-management/gt-im-performance-measures (last visited Oct. 18, 2020).

B. Effective and code-compliant corrosion control systems should not be a basis for ineligibility.

The Associations recognize the importance of effective corrosion control and seek to achieve effective protection. However, PHMSA should not treat the use of the -100 mV polarization voltage shift criterion or the use of linear anodes on a class change segment as a basis for ineligibility from § 192.618. Use of 100 mV polarization voltage shifts and linear anodes are code-compliant and effective corrosion control strategies, and PHMSA should not penalize operators for choosing to employ those strategies. Instead, PHMSA should base eligibility on the existing performance standard in § 192.457. Segments with "ineffective coating," as defined by § 192.457, should be ineligible for § 192.618. Similarly, segments should be ineligible if they use tape coating or shrink sleeves for which the operator has experienced a history of disbondment/shielding. Regardless of the corrosion control methodology selected by an operator, periodic monitoring and assessment of corrosion control effectiveness should and will be required under proposed § 192.618.

In the NPRM, PHMSA associates use of the -100 mV polarization shift and linear anodes with poor coating. However, the decision to use these corrosion control tools may have nothing to do with coating effectiveness—for example, use of these tools could be driven by soil characteristics, in order to reduce cathodic protection interference on foreign pipelines, etc. As evidence of that point, operators currently use both -100mV polarization shifts and linear anodes with new, FBE-coated pipe.

The science behind 100 mV polarization and why it is effective was described by Barlo.[35] The -100 mV polarization shift comes directly from Part 192 and has historically been used as a value indicating appropriate corrosion protection.[36] Furthermore, NACE SP0169 provides multiple criteria to address cathodic protection challenges and clearly states that the -100 mV polarization shift is indicative of effective protection.[37]

In the NPRM, PHMSA points to concerns that an environment may exist with potentials below -.850mV that is more conducive to stress corrosion cracking, referencing the Second Edition of Peabody.[38] It is important to note that the Third Edition of Peabody published in 2016[39] recognizes 15 years additional experience in managing corrosion and synchronizes with NACE SP0169, classifying the cracking-related concern with potentials below -.850mV as a "caution," instead of the "should not be used" recommendation from the Second Edition. As stated in Peabody, the relationship between off potentials and cracking is temperature dependent. The range in which cracking can hypothetically occur is narrow at the temperatures at which pipelines operate. Furthermore, for any segments that *are* in the range of cracking susceptibility, PHMSA's proposed § 192.618(b)(1)(iii) requires operators to assess for cracks using an EMAT ILI tool, and any cracking identified will be managed in accordance with the robust crack anomaly response requirements proposed in § 192.618(c). Additionally, § 192.618(e) requires operators to inspect exposed pipe for cracking at available opportunities.

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[35] T.J. BARLO, ORIGIN AND VALIDATION OF THE 100 MV POLARIZATION CRITERIA (2001).
[36] *See* 49 C.F.R. Part 192, Appendix D(I)(3).
[37] NACE SP0169 at 17 (2013); ISO 15589 at 58 (2015).
[38] NPRM at 65,158 n.89 (citing Peabody, A.W., Control of Pipeline Corrosion (R.L. Bianchetti, P.E., ed., NACE Press 2d. ed., 2001)).
[39] Peabody, A.W., Control of Pipeline Corrosion at 47 (R.L. Bianchetti, P.E., ed., NACE International, 2018).

PHMSA also expresses concerns in the NPRM about the use of -100 mV polarization shifts in the presence of stray currents. However, this concern should be addressed by proposed § 192.618(f)(4), which requires operators to survey for and mitigate interference currents affecting § 192.618 segments.

Similarly, placement of linear anodes may be the most effective way to cathodically protect a segment or portion of a segment. When linear anodes are used, the anode (the source of cathodic protection) is physically closer to the cathode, the pipeline. In many cases, linear anodes are used on segments with good coating but where deep ground beds are impracticable because of bedrock and/or right-of-way acquisition for conventional ground beds is impracticable because of permitting or congestion. Additionally, significant alternating current (AC) interference from high voltage power lines is often mitigated with use of linear anodes.[40]

PHMSA also should not deem all pipe with "tape coating" or "shrink sleeves" ineligible. Part 192 permits the use of tape coating and shrink sleeves. The Associations share PHMSA's concern that *certain vintage* coatings may disbond and shield CP. Disbondment and shielding of CP is a function of original application of coating and to some degree the environment in which the coating resides. This is less likely to occur with more modern applications, so a broad disqualification of tape coating and shrink sleeves is inappropriate. Furthermore, disbonding and shielding will already be managed through the integrity assessment requirements of §192.618. Metal loss associated with shrink sleeve shielding is readily identified and characterized with axial MFL ILI because the disbondment tends to occur adjacent to the girth weld. In a similar way, metal loss occurring at locations where tape coating disbonds and shields can be identified and characterized with axial MFL. PHMSA has proposed conservative metal loss response criteria, especially at girth welds, which will ensure that any disbondment/shielding-driven metal loss is addressed quickly.

Instead of basing § 192.618 eligibility on operators' choice of code-compliant corrosion control tools, PHMSA should base eligibility on the agency's existing performance standard for coatings. Segments should be ineligible for § 192.618 if the pipe does not have effective external coating. Section 192.457 already defines "ineffective coating," stating that "a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements."[41]

Under this eligibility standard, operators should evaluate and document whether a class change segment has effective coating, as defined in § 192.457, based on a variety of available tools. An operator could demonstrate effective coating by comparing the results of one or more of the following inspections of a potential § 192.618 segment to values for bare pipelines to show substantial differences: cathodic protection current requirement (per § 192.457); calculated average current density (per § 192.457); measured coating conductance (per NACE TM0102); AC attenuation surveys (per NACE TM0102); representative visual coating assessments; other macro coating assessment methods such as C-SCAN or AC attenuation (per NACE TM0102); or other micro coating assessment methods such as ACVG, DCVG, and Pearson survey (per NACE TM0102). Furthermore, existing Part 192 requirements for monitoring

[40] Also, no definition of "linear anode" is proposed in the NPRM. The exclusion could be interpreted to exclude ground beds that use continuous ribbon-type anodes in a vertical column, or zinc ribbon used for AC grounding or gradient control.
[41] 49 C.F.R. § 192.457(a).

cathodic protection current sources on a bi-monthly basis serve as a tool for evaluating continued coating effectiveness as current demand is a direct function of coating quality and effectiveness.

Similarly, segments should be ineligible if they use tape coating or heat shrink sleeves for which the operator has experienced a history of CP shielding.

C. Presence of cracking should not automatically invalidate an existing § 192.618 program.

It appears that PHMSA is proposing in the NPRM that the presence of cracking on or near a segment already operating under § 192.618 would automatically invalidate the § 192.618 program and require operators to replace the class change segment or reduce pressure, no matter how many years that the segment had been successfully managed under § 192.618. This is unreasonable because operators will be required to commit substantial resources to implementing a § 192.618 program on a class change segment, much of which would be wasted if the presence of a single crack could then require the operator to replace the pipe or reduce MAOP anyway. PHMSA's proposal to apply this requirement not only to the class change segment but also five miles upstream and downstream of the segment is particularly problematic because the upstream/downstream pipe could be different pipe, with different coating, in a different environment, and cracking is often an isolated, environment-specific phenomenon.

More importantly, this proposal is unnecessary for safety because PHMSA has proposed strict requirements for managing cracking in § 192.618. Segments susceptible to the threat of cracking must be inspected using an EMAT ILI tool, or a non-ILI methodology with notification to PHMSA, and any identified cracks must be remediated in accordance with conservative crack response criteria in § 192.618(c). This crack management approach is consistent with the framework that PHMSA established and the GPAC endorsed in the "Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments" final rule and the pending final rule on "Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments." Nowhere in those rulemakings did PHMSA propose an automatic requirement to replace pipe or permanently reduce pressure due to the presence of a remediable crack.

Instead of invalidating a § 192.618 program whenever a crack is discovered, PHMSA should require operators to notify the agency of any cracking on the class change segment and propose a crack remediation and management plan. This requires operators to develop a focused, situation-specific response and provides PHMSA awareness of and opportunity for input on the plan.

If PHMSA does not agree with the notification approach, the ineligibility criteria for cracks should be revised to align with the proposed scheduled response criteria for cracks in § 192.618(c). PHMSA's proposed criteria in § 192.618(a)(4)(viii) is significantly more conservative than the scheduled response criteria. If an operator is managing its pipeline in such a way that the one-year cracking criteria is never triggered, this is indicative of an effective and conservative crack management program.

Finally, there appears to be a typo in § 192.618(a)(4)(viii). Even without any anomalies, it may be impossible to achieve a 1.5xMAOP predicted failure pressure (PFP) on a class 1 to class 3 change segment because the pipe design factor is 1.39xMAOP.

D. Pipe with wrinkle bends should be eligible for § 192.618 unless geohazard threats are also present.

PHMSA should revise § 192.618(a)(4)(ii) to exclude only those segment containing wrinkle bends in the presence of geohazard threats. A broad exclusion of all segments with wrinkle bends would significantly limit the application and benefits of § 192.618 with little safety benefit.

The failure frequency of wrinkle bends is extremely small; the Associations estimate that only about 1 in 8,000 wrinkle bends have failed over approximately seventy years of service.[42] The vast majority of these failures occurred prior to the development of modern pipeline integrity practices. Wrinkle bend failures are historically associated with outside forces. Furthermore, most of these incidents are leaks, as opposed to ruptures, as wrinkle bends tend to fail as a fracture of part of the pipe circumference.

The use of § 192.618 in lieu of pipe replacement on pipelines that contain wrinkle bends has the added safety benefit of avoiding disturbances to wrinkle bends that may be present on upstream/downstream segments that are just outside of the class change segment. A construction project to replace the class change segment can introduce new outside forces that could act on the wrinkle bends intended for continued service (those outside of the class change segment), creating new risk that did not exist before the replacement project. Similarly, a pressure reduction to comply with § 192.611 may do little to prevent a wrinkle bend failure. In the rare instances where wrinkle bend failures have occurred, usually outside forces and not pipe hoop stress contributed to the failure mechanism.

E. PHMSA should allow for integrity management of shorted casings.

In proposed § 192.618(f)(8), PHMSA proposes that operators must clear shorted casings. In a March 2019 interpretation of existing external corrosion control requirements for shorted casings (§ 192.467), PHMSA indicated that shorted casings which are impractical to clear can be managed though an approach involving monitoring with ILI tools.[43] The Associations propose that PHMSA provide an integrity management option for managing shorted casings on class change segments operating under proposed § 192.618 when it is impracticable or unsafe to eliminate a short.

V. <u>PHMSA Should Align § 192.618 with Existing/Pending Rulemakings</u>

A. Pipelines without TVC tensile strength records should be eligible for § 192.618.

TVC tensile strength records should not be required for a class change segment to be eligible for § 192.618. In the NPRM, PHMSA proposes that pipe segments without records of attributes required for anomaly evaluation would not be eligible for proposed § 192.618, unless the operator verifies the missing properties.[44] In general, the Associations support this restriction, but tensile strength data is not required

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[42] The Associations are aware of at least 230,000 wrinkle bends in service. Twenty-six (26) wrinkle bend failures, going back to 1946, were identified in the PRCI report "Wrinklebend Evaluation Study and Tool Development (MATV-1-2)" (2014). The Associations are aware of approximately four (4) additional wrinkle bend failures. Therefore, 30/230,000 yields a failure rate of approximately 1 in 8,000 over approximately 70 years of service.

[43] PHMSA Letter of Interpretation, PI-18-0003 (Mar. 11, 2019).

[44] *NPRM* at 65,157. For example, operators could verify missing properties for a § 192.618 class change segment using § 192.607.

for anomaly evaluation or MAOP calculations, whereas diameter, wall thickness, grade, seam type, and yield strength are needed for those calculations.

Although current technologies for in-situ material property verification may produce a measure of tensile strength, material verification should not be required just for tensile strength, a data point without practical utility. Furthermore, material verification technology may emerge in the coming years that does not produce a measure of tensile strength but produces the material properties necessary for anomaly evaluation and MAOP calculations, and use of that technology should not be precluded.

B. The requirement to validate all tools in accordance with API RP 1163 Level 3 is unnecessary for safety and inconsistent with API RP 1163.

Under proposed § 192.618(b)(4), PHMSA would require operators to validate all ILI runs on class location change in-line inspection segments in accordance with API RP 1163 *Level 3*. The Associations support requiring validation of ILI runs in accordance with API RP 1163, but the requirement to perform all validations in accordance with Level 3 of that standard is not practicable or necessary for safety.

API RP 1163 Level 3 is often not practicable to achieve because it requires the use of "extensive measurements" to validate ILI tool performance. Extensive measurements are often not possible, particularly where the goal is to promote in-line inspection of segments that have not been previously inspected and segments where few anomalies have been identified. The segments that are in the best condition, and therefore the best candidates for § 192.618, may have experienced few anomalies and therefore not have "extensive measurements" of anomalies to validate ILI tool performance.

The purpose of a Level 3 assessment is for ILI vendors to derive and substantiate their tool's performance specification or for an operator to *supersede* the specification provided by the vendor. A Level 3 analysis by the operator is typically not possible for the full spectrum of feature morphologies reflected in a ILI vendor's specification—not only would this require an inordinate number of unnecessary digs, but the range of feature types within the tools specification may not even be present in the line.

Level 3 validation is also not necessary for safety. API 1163 provides proven, technically sound validation processes through Level 1 and Level 2 validation that prove with a high degree of confidence that the tool performed in accordance with the tool vendor's specifications. Notably, PHMSA's current requirements for pipelines in high consequence areas (HCAs) at § 192.921(a)(1) require operators to validate ILI tool performance in accordance with API RP 1163, but not Level 3 specifically. The validation process appropriate for HCAs should be appropriate for class change segments. For example, to comply with the Subpart O requirements, the Associations' members use validation methods such as unity charts, allowing for comparison of as-called (by ILI) versus as-found measurements in an excavation. Error bounds representing an ILI tool performance specification (+/- %) are added to the charts. In the event that outliers occur, the operator can work with the ILI vendor to resolve.

Furthermore, even where extensive measurements to comply with API RP 1163 Level 3 are possible, they may not be valuable where an operator can instead incorporate appropriate conservatism into anomaly evaluation calculations. PHMSA has proposed highly conservative anomaly response criteria for class change segments. For example, the proposed one-year condition requiring examination of an anomaly on a class change segment whose PFP is equal to 1.39xMAOP would occur nine years prior to when it would be predicted to fail using the well-established Figure 7-1.1 [formerly Figure 4] in ASME B31.8S.

Extensive ILI validation measurements are not necessary on top of such conservative anomaly response criteria.

In addition to the API RP 1163 Level 3 requirement, PHMSA has also proposed under § 192.618(b)(4)(ii) that operators be required to validate anomalies using "a minimum of 4 anomaly validations or 100 percent of anomalies, whichever is less." Although the four validation dig requirement is more practicable than API RP 1163 Level 3, the four dig requirement is also not necessary to validate tool performance. There is no technical basis for selecting four digs. Instead, PHMSA should simply require validation to be conducted in accordance with any of the pathways allowed under API RP 1163.

C. PHMSA should allow for the use of prior assessments in § 192.618.

Proposed §§ 192.618(b) and (f) do not currently provide guidance regarding whether operators can utilize prior ILI, interference current survey, or close interval survey (CIS) data to meet baseline assessment requirements. Assessments performed a few years before initiating the § 192.618 for a class change segment and in accordance with the relevant requirements in Part 192 still provide the necessary integrity information for purposes of a baseline assessment. Where information from a prior assessment is available and still valid, PHMSA should require the next assessments to be scheduled in accordance with the reassessment intervals specified in §§ 192.618(b) and (f). This is consistent with requirements in §§ 192.710 and 192.921. PHMSA should also require that any § 192.618 remediation requirements associated with prior assessments and still outstanding must be completed within 24 months of the class change.

D. Anomaly response criteria in § 192.618 should align with those endorsed by the GPAC in March 2018.

The Associations generally support the anomaly response criteria in proposed § 192.618(c). However, a few of the criteria deviate significantly from those endorsed by the GPAC during its consideration of the "MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments" rulemaking in March 2018. These changes would force operators to focus on addressing low-risk anomalies instead of pursuing more valuable safety work.

First, there is no technical justification for PHMSA's proposed response criteria in § 192.618(c)(3)(i)(A)–(B), which would require operators to remediate anomalies within one year that have wall loss or crack depth greater than 40%, *regardless of* PFP. Wall loss in and of itself is an incomplete measure of risk. PFP is a much more informed basis for categorizing anomalies, because PFP calculations consider anomaly depth, length, and pipe material properties to directly evaluate the extent to which an anomaly is impairing the pipeline's ability to safely operate at its MAOP. PHMSA's other proposed criteria in § 192.618(c) ensure that any anomaly that reduces the PFP of the class change segment below 1.39 will be remediated within one year, and so the additional depth-based criterion is unnecessary. For example, pits with depths exceeding 40% but with PFPs greater than 1.39 do not warrant urgent treatment.

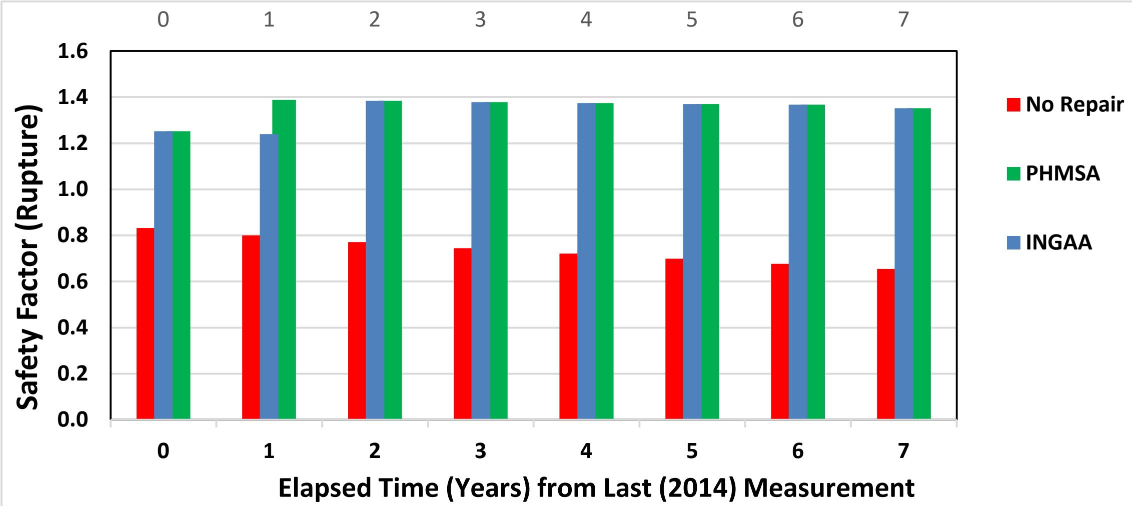
Second, scheduled response requirements in the in-line inspection area—outside of the segment where the class change has occurred—should be set at two years, not the one year proposed by PHMSA throughout § 192.618(c). In the "MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments" rulemaking, PHMSA has proposed one-year scheduled responses in HCAs and two-year scheduled responses in non-HCAs. Although the associations support treating the class change segment itself as an HCA—including the one-year scheduled response requirement—there is no technical justification for requiring one-year scheduled responses in the rest of the in-line inspection area. The pipe in the in-line inspection area and outside of the class change segment is no different than any other non-HCA segment and should be regulated as such.

The Blade Report provides examples to help demonstrate that § 192.618 would still provide sufficient safety with the two changes proposed above by the Associations.[45] For corrosion anomalies, Blade indicates that risk outcomes "may be considered equivalent" regardless of the independent 40% depth criterion. Blade notes that "[r]epair criteria based solely on depth do not demonstrate benefit in terms of reliability. This is because failure is dictated by both depth and length of the anomaly. Therefore, a deep anomaly often will not have an appreciable effect on failure pressure unless it is of adequate length. It is suggested that the criteria include both depth and length of the anomaly to create a more rational basis for repair decisions."

For SCC anomalies on the example segment studied by Blade, after removing the 40% depth criterion and applying a two-year scheduled response timeframe in the class 1 in-line inspection area, the probably of failure for the class 1 to 3 change segments would never exceed $1x10^{-7}$ during the assessment interval (following initial immediate repairs). For comparison, the probably of failure targeted by Canadian Standard CSA Z662 for oil and gas pipeline systems is $1x10^{-4}$ per km/yr, the probability of failure targeted by the American Association of State Highway and Transportation Officials for bridge beam designs is between $1x10^{-4}$ and $1x10^{-5}$, and the probability of failure targeted by AFCEN for French nuclear installations is $1x10^{-7}$. The Blade Report notes that after the Associations' proposed changes, § 192.618 would "lead to the same outcomes" for class 1 to 3 locations.

Additionally, after the Associations' proposed changes to the anomaly response criteria, the highest probability of failure due to SCC anomalies in class 1 locations during the seven-year assessment interval would never exceed $1x10^{-3.9}$, which is only a slight change from the maximum probability of failure due to SCC anomalies without the Associations' proposed changes, $1x10^{-4}$. Figure 2 above, and reproduced as Figure 3 below, shows the higher safety factor and lower probability of failure for SCC anomalies provided in the Class 1 inspection area with § 192.618 applied and the anomaly response criteria revisions recommended by the Associations (labeled "INGAA" in Figure 2 below). After incorporating the revisions recommended by the Associations, the safety factor remains above 1.2 for the entire assessment interval.

[45] *See supra* note 20.



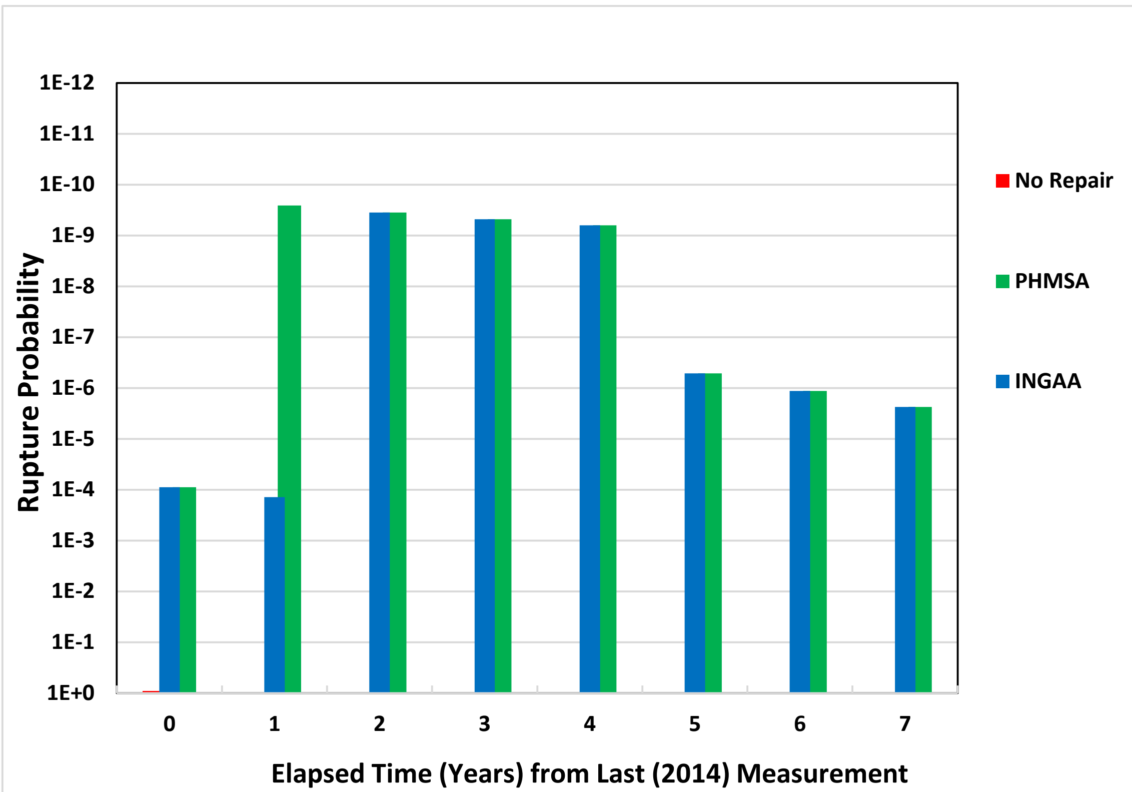


Figure 3. Probability of failure and safety factor results due to SCC anomalies in an example Class 1 inspection area where § 192.618 is applied 1) as proposed by PHMSA (labeled "PHMSA"), 2) with the revisions recommended by the Associations (labeled "INGAA"), and 3) compared to a class change pipe replacement (labeled "no repair").

Third, the requirement to consider growth before treating a condition as "monitored" in § 192.618(c)(5) is highly confusing and contradictory and should be removed. Such a requirement would defeat the entire purpose of "scheduled" conditions. Scheduled conditions must be remediated because, based on the PFP of those anomalies, they could grow to failure before the next ILI assessment interval. If operators must consider growth before establishing which anomalies are "scheduled" and which are "monitored," then many anomalies with PFPs well above the PFP factors provided in § 192.618(c) would become "scheduled." If PHMSA wishes to take a growth calculation-driven approach to integrity management, then operators should be required to consider whether anomalies would grow to *immediates* prior to the next assessment interval. However, PHMSA has previously rejected this approach for most anomaly types in favor of prescriptive scheduled response criteria. PHMSA must pick one approach or the other in order for the regulations to be coherent; the two concepts do not work well together. The GPAC recognized this conflict at its March 2018 meeting and rejected PHMSA's proposal to add growth consideration requirements to monitored response calculations.[46]

Finally, PHMSA should not require notification whenever an operator conducts a strain or fatigue analysis as part of a dent engineering critical assessment (ECA) using a method other than finite element analysis (FEA). Considering the number of inspections performed annually and dents that will be reported in ILI assessments, notifying PHMSA of on every strain and fatigue analysis is impractical and would likely become a significant administrative burden on the agency. PHMSA should require operators to select technically appropriate ECA methods based on the nature of the dent and available data. For some dents, a basic strain analysis will be sufficient to demonstrate that remediation is not necessary for safety, particularly because the vast majority of gas transmission pipeline segments are not subject to the threat of cyclic fatigue. Similarly, operators should be permitted to use operational pressure data to demonstrate that the potential for fatigue damage does not exist, and then only conduct full finite element analysis where there is potential for damage due to fatigue is present. At the March 28, 2018 GPAC meeting, the committee recommended that PHMSA consider ECA methods other than FEA.[47]

The concept of using ECA techniques that do not require a full FEA for dent assessment is consistent with the methods presented in the API RP 1183, *Assessment and Management of Dents in Pipelines*, and is likewise consistent with a wide range of fitness for service techniques applied to cracks, corrosion, and other features in recognized technical standards. PHMSA should consider incorporating API RP 1183 by reference in proposed § 192.712.

E. PHMSA should remove the requirement that automated valves be "controlled" by a SCADA system.

PHMSA's GPAC recently met to discuss PHMSA's Valve Installation and Minimum Rupture Detection Standards proposed rulemaking. During that meeting, PHMSA proposed and the GPAC unanimously agreed that operators should be permitted to protect class change segments using automated shutoff valves that actuate based on local pressure sensors rather than SCADA system control.[48] To be consistent with that recommendation, PHMSA should revise § 192.618(g) to allow both remotely-controlled valves and automated shutoff valves that are controlled based on local pressure sensors.

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[46] GPAC Meeting Tr. 65 –80 (Mar. 28, 2018), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=972.
[47] GPAC Meeting Final Voting Slides at 20 (Mar. 26–28, 2018), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=966.
[48] GPAC Meeting Final Voting Slides at 4 (July 22, 2020), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1125.

F. PHMSA should clarify that the ILI requirements in § 192.618(b)(1) are based on threats to which the class change segment is susceptible.

In proposed § 192.618(b)(1), it appears that PHMSA is proposing to require operators to run ILI tools to address specific threats on each class change segment and the surrounding in-line inspection segment, *if the class change segment is susceptible to that threat*. The Associations request that PHMSA make this explicitly clear in § 192.618(b)(1). Obviously, there is no value in running ILI tools to address threats that a segment is not susceptible to. For threats that do not affect the class change segment but exist elsewhere on the pipeline, such as on the in-line inspection segment, those threats will be addressed through other applicable provisions of Part 192, such as Subpart O, § 192.710, etc.

G. § 192.609 class change studies should not be required until class changes actually occur.

In § 192.618(a)(1), PHMSA proposes to require that operators perform an annual § 192.609 study on the in-line inspection segment—outside of where the class change has occurred. PHMSA has not provided a basis or purpose for this new annual assessment requirement. This requirement is inconsistent with the premise of § 192.609. Section 192.609 was designed to provide a one-time fitness for service assessment following a change in class location. It is unclear what PHMSA wishes to accomplish by requiring this assessment outside of the class change segment again and again every year. Other than being "near" a class change, the in-line inspection area is no different than any other transmission pipe on the system.

The integrity assessment requirements for in-line inspection segments in § 192.618, and all of the other Part 192 requirements applicable to in-line inspection segments, will continue to provide a safety assessment surrounding the class location change segment if and until a class change occurs on the in-line inspection segment. PHMSA should not require a § 192.609 until a class change has actually occurred.

H. Additional P&M measures required under § 192.618(f) should also qualify as additional P&M measures required under § 192.935(a).

In § 192.618(a), PHMSA proposes to require class change segments to be classified as HCAs and also to require a list of additional preventative & mitigative (P&M) measures in § 192.618(f) that are not required under Subpart O. In general, the Associations support this approach to managing the integrity of class change segments. However, this creates a potential conflict with § 192.935(a), which requires operators to implement "additional measures beyond those already required by Part 192." Many of the P&M measures required under § 192.618(f) are implemented on HCA segments today to comply with § 192.935(a). So that it is practicable for operators of § 192.618 segments to continue complying with § 192.935(a), PHMSA should clarify that § 192.618(f) requirements qualify as "additional measures" to meet the requirements of § 192.935(a).

I. PHMSA should require anomaly discovery within 240 days for non-HCA segments.

At its March 28, 2018 public meeting, PHMSA proposed and the GPAC endorsed providing 240 days for anomaly discovery outside of HCAs.[49] This is because more advanced ILI tools, such as EMAT, often require more complex and time-consuming data analysis. For consistency, PHMSA should incorporate the

[49] GPAC Meeting Final Voting Slides at 24 (Mar. 26–28, 2018).

same requirement here in proposed § 192.618(b)(5), instead of the 180-day requirement proposed in the NPRM.

J. Operators should be permitted to use all effective measures to mitigate loss of cover.

In proposed § 192.618(f)(5), PHMSA proposes to require that where the depth of cover is less than 24 inches in areas of non-consolidated rock, the operator must either lower the pipe or add cover. This excludes other effective measures of mitigating the risk posed by a loss of cover—such as installing above-ground safety barriers or adding concrete over the pipe.

Pipeline depth of cover can naturally recede over time due to erosion. Restoring construction cover depths for short class change segments will often be impracticable. The only options to significantly increase depths of cover for short sections of pipe are to (1) lower a substantial section of pipeline, exposing the line to strain and low spots where liquids could collect, (2) install elbows or bends to lower the replaced pipe, which would again subject the small sections to liquid buildup and may make the pipeline segment incapable of assessment with in-line inspection, or (3) provide additional cover for the short sections, which would result in irregular mounds of soil along the right-of-way potentially leading to disputes with landowners. None of these are practical solutions, at least not in all cases. Moreover, depending on the location of the right-of-way, operators may face access and environmental permitting issues in order to add additional cover.

K. Pressure tests meeting Subpart J requirements should be acceptable for compliance with § 192.618.

In § 192.618(a)(4)(v), PHMSA proposes to require that all segments managed in accordance with § 192.618(a) have an eight-hour pressure test to at least 1.25xMAOP and in accordance with Subpart J. In general, the Associations strongly support this requirement, but PHMSA should revise it to address scenarios where an eight-hour test is not required for compliance with Subpart J. For example, under § 192.505(d), fabricated units and short sections of pipe may be tested for four hours.

L. Direct assessment should be allowed with notification to PHMSA.

Direct assessment should be allowed under proposed § 192.618(b)(1)(v), with prior notification to PHMSA. Direct assessment has proven to be an effective integrity management tool when employed correctly, using NACE recommended practices incorporated by reference by PHMSA,[50] to address the specific set of threats that it is designed to address. For example, if an operator employs SCCDA and a category 2 or larger crack is found, the segment will then be assessed by EMAT or hydrostatic testing. The GPAC recognized the value of direct assessment when it voted to retain it as an allowable integrity assessment method in § 192.710 and Subpart O during its March 2, 2018 GPAC meeting.[51]

PHMSA and other stakeholders have previously expressed concerns with direct assessment being used *incorrectly.* Notification gives PHMSA the opportunity to object if the agency believes DA is being applied incorrectly.

[50] *See* § 192.7

[51] GPAC Meeting Final Voting Slides at 2 (July 22, 2020).

M. § 192.18 should be updated to reflect its references to § 192.618.

Section 192.18(c) currently cross-references other code sections for which the notification procedures contained in that section may be applied. Section 192.18(c) should be updated to reflect PHMSA's proposal to cross-reference § 192.18 throughout § 192.618.

VI. PHMSA should continue to allow a reasonable variety of "cluster" definitions across the industry.

PHMSA has elected not to propose any changes to "clustering" methodologies in this NPRM. Nevertheless, the Associations wish to document our understanding of current clustering requirements and leading practices. If PHMSA disagrees with this understanding, this likely indicates a lack of clarity regarding clustering requirements, and PHMSA should seek to resolve any confusion by clarifying clustering requirements in a future proceeding.[52]

Whenever "a Class 2 or 3 location is required by a *cluster* of buildings in otherwise open country,"[53] the clustering rule allows an operator to end the class 2 or 3 location 220 yards from the nearest building in the cluster.[54] The Part 192 regulations have never defined "cluster" or prescribed how multiple clusters within a sliding mile should be treated for purposes of class location determinations.

A. Nothing in the text or history of Part 192 requires operators to treat a single structure as a "cluster."

In the ANPRM, PHMSA suggested that "even a single house could form the basis of a second cluster."[55] Although an operator could define "cluster" in that way, the Associations wish to emphasize that nothing in the text or history of Part 192 *requires* that interpretation.

Without a definition in the regulations, operators must first look to the plain language of the regulation and the rulemaking history. While courts generally defer to an Agency's interpretation of its own regulations, an alternative reading may be compelled by either the plain language of the regulation or evidence of the Agency's intentions when the rule was first promulgated.[56] The text of 49 C.F.R. § 192.5(c) indicates that the Agency intended that a cluster would consist of multiple buildings, not a single structure. The regulation provides that "[w]hen a cluster of *buildings* intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster."[57]

There were no discussions by either the Agency or the Technical Pipeline Safety Standards Committee ("the Committee") at the time of the 1970 rulemaking to indicate that one structure would be treated as a cluster. On the contrary, the rulemaking and ASME B31.8 history suggest that the purpose of the

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[52] PHMSA's interpretation of clustering requirements have significant impacts. For example, just one large interstate pipeline estimates that changing its current clustering practices to implement "a cluster of one" would result in over $50 million of pipe replacements.
[53] PHMSA Letter of Interpretation to Mr. Donald R. Linger, V.P., Transmission, Algonquin Gas Transmission Co., PI-95-0100 (Apr. 13, 1995) (emphasis added).
[54] 49 C.F.R. § 192.5(c)(1)-(2).
[55] Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. 36,861, 36,863 (July 31, 2018).
[56] *Kisor v. Wilkie*, 139 S.Ct. 2400 (2019); *Thomas Jefferson Univ. v. Shalala*, 512 U.S. 504, 512 (1994) (citing *Gardebring v. Jenkins,* 485 U.S. 415, 430 (1988)).
[57] 49 C.F.R. § 192.5(c)(2) (emphasis added).

clustering provision was to allow "thinly populated areas" in "otherwise open country" to remain as class 1 locations, except for the area within 220 yards of a cluster of buildings that prompted the higher-class designation.[58] "Thinly populated areas" and "open country"—such as the grazing land and farm land referenced in the historical definition for class 1 locations—often have more than zero buildings.[59] In 1970, during the discussions of the Committee on the proposed clustering rule, Mr. George White, Chief Engineer of the Tennessee Gas Pipeline Company, a member of the Committee, referred to a cluster as a "grouping within one mile."[60] In the text of the present regulation, class 1 locations are defined by the presence of up to 10 buildings intended for human occupancy, supporting the assertion that "thinly populated" and "open country" does not require zero buildings.

In fact, when questioned about the meaning of the word "cluster," PHMSA has directed the industry to the dictionary definition. In 1992, in response to a proposal to amend the clustering rule, AGA asked the Agency to explain what constituted a cluster.[61] The Agency responded that "the term is used in its ordinary dictionary sense, and, in RSPA's experience, has not been a significant source of misunderstanding."[62] The Merriam-Webster dictionary defines a cluster as "*a number of similar things that occur together.*"[63] The dictionary authors offered examples including "a group of buildings and especially houses built close together."[64] A "group" is further defined in the dictionary as "two or more figures forming a complete unit in a composition" or "a number of individuals assembled together or having some unifying relationship."[65] In 2004, PHMSA acknowledged that this particular definition (a number of similar things, a bunch, or a group) is the "ordinary meaning" the Agency envisioned when it used the term "cluster."[66] PHMSA further confirmed this approach in 2011 by stating in an enforcement case that "[a] *group* of buildings within the class location unit is sometimes referred to as a 'cluster' of buildings."[67]

A requirement that operators include a single house in their "cluster" definition conflicts with the rulemaking history and the recognized dictionary definition. A single structure is not part of a number or group of buildings and has no unifying relationship with any other buildings. If anything, the defining characteristic of a single structure when viewed from this perspective is that it lacks each of these

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[58] Establishment of Minimum Standards, 35 Fed. Reg. 13,248, 13,251 (Aug. 19, 1970).
[59] *Id.*
[60] Tr. of Technical Pipeline Safety Standards Committee, at 248:8-9 (June 24, 1970), https://www.regulations.gov/document?D=PHMSA-2014-0095-0034.
[61] Comments of the American Gas Association at 4, Docket No. PS-124; Notice 1 (Sept. 30, 1992), https://www.regulations.gov/document?D=PHMSA-2015-0073-0007.
[62] Regulatory Review; Gas Pipeline Safety Standards, 61 Fed. Reg. 28,770, 28,772 (June 6, 1996); PHMSA's reliance on the dictionary is consistent with the approach that courts have used in determining the ordinary meaning of terms that do not have any special legal significance. *See e.g.*, *Muscarello v. United States*, 524 U.S. 125, 128 (1998).
[63] https://www.merriam-webster.com/dictionary/cluster (last visited Oct. 30, 2020) (emphasis added).
[64] *Id.*
[65] https://www.merriam-webster.com/dictionary/group (last visited Oct. 30, 2020).
[66] PHMSA Letter of Interpretation to Mr. Joseph Peterson, Natural Resources Engineering Co., PI-04-0106 (Apr. 20, 2004) ("In the regulations, the term, 'cluster' is used in its ordinary dictionary sense, and has not been a significant source of misunderstanding. The dictionary meaning is: a number of similar things together, a bunch, a group.").
[67] *In the Matter of El Paso Pipeline Corp. and ANR Pipeline Corp.*, Final Order at 3, CPF No. 4-2007-1007 (Mar. 10, 2011) (emphasis added).

features. Accordingly, a single structure cannot be considered a cluster under any reasonable understanding of the ordinary dictionary definition.

Without any contrary guidance from PHMSA, operators have understood that they have the obligation to determine how many structures reflect "a number" or "group" of buildings, in accordance with their own class location program. In the past, when PHMSA has relied on undefined terms in the regulations, the Agency has confirmed that each operator must rely on "commonly used definitions found in reputable dictionaries" and develop an appropriate definition in its own procedures.[68] For example, the Agency does not define "prevalent" in 49 C.F.R. § 192.5(b)(4) and has allowed operators to apply "prevalent" based on public safety and environmental concerns.[69] The same flexibility should be offered to operators in applying "cluster."

B. PHMSA should continue its current practice of allowing operators to develop and document a reasonable, risk-based clustering methodology.

Because PHMSA has chosen not to define "cluster" in Part 192 for nearly five decades, each operator has established its practice for identifying clusters as part of its class location program. These practices have often been refined over several decades and are now firmly imbedded in operators' pipeline safety programs. Therefore, PHMSA should continue to provide operators flexibility to develop and document reasonable, risk-based approaches to clustering.

For the past fifty years, operators have understood that they have the obligation to develop procedures to identify "clusters of buildings intended for human occupancy" in accordance with § 192.5(c)(2) and determine the impact of any identified clusters on a pipeline's class location. Specifically, operators' procedures for determining class location should include the following:

1. The operator's definition of a "cluster," consistent with § 192.5(c)(2). Depending on operator's process, this could include definitions for "primary," "secondary," or other types of clusters;
2. The operator's process for identifying clusters;
3. The operator's process for establishing or modifying class location designations based on cluster identification, including a description of how the presence of primary, secondary, or other clusters affects the designation of a segment as class 1, class 2, or class 3. This process should produce higher class location designations for higher-consequence segments; and
4. A description of how the operator determines the starting and ending point of each class location segment affected by a cluster, consistent with the requirements of § 192.5(c)(2).

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[68] PHMSA Letter of Interpretation to Mr. Joel E. Kohler, P.E., Enterprise Products Co., PI-07-0102 (Apr. 6, 2007).
[69] *Id.* ("PHMSA does not define 'prevalent' nor do we specify the number (or percent) of buildings with four or more stories that make up a Class 4 location. . . . [The operator] must consider public safety and the protection of the environment in deciding whether four or less four story or more buildings means these buildings are prevalent (i.e., extensive or widespread). You must explain your rationale to PHMSA, if questioned.").

VII. Consolidated Recommendations for Changes to Regulatory Text of Proposed Rule

Below is a consolidated set of Associations' proposed modifications to the Proposed Rule regulatory text **in red**. These proposed modifications were explained and included in Parts I—VI above.

§191.22 National Registry of Operators.

[. . .]

(c) *Changes.* Each operator of a gas pipeline, gas pipeline facility, UNGSF, LNG plant, or LNG facility must notify PHMSA electronically through the National Registry of Operators at *https://portal.phmsa.dot.gov* of certain events.

(1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:

(i) Construction of any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60-day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;

(ii) Construction of 10 or more miles of a new pipeline;

(iii) Construction of a new LNG plant, LNG facility, or UNGSF;

(iv) Maintenance of a UNGSF that involves the plugging or abandonment of a well, or that requires a workover rig and costs $200,000 or more for an individual well, including its wellhead. If 60-days' notice is not feasible due to an emergency, an operator must promptly respond to the emergency and notify PHMSA as soon as practicable;

(v) Reversal of product flow direction when the reversal is expected to last more than 30 days. This notification is not required for pipeline systems already designed for bi-directional flow; or

(vi) A pipeline converted for service under §192.14 of this chapter, or a change in commodity as reported on the annual report as required by §191.17.

(2) An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:

(i) A change in the primary entity responsible (*i.e.,* with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs;

(ii) A change in the name of the operator;

(iii) A change in the entity (*e.g.,* company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, UNGSF, or LNG facility;

(iv) The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to part 192 of this subchapter; or

(v) The acquisition or divestiture of an existing UNGSF, or an LNG plant or LNG facility subject to part 193 of this subchapter.

(vi) A change in the classification of a pipeline segment from a Class 1 **or Class 2** to a Class 3 location where the operator chooses to confirm or revise the maximum allowable operating pressure (MAOP) in accordance with § 192.611(a)(4). The notification must include the following information about the ~~Class 1 to~~ Class 3 location **change** segment: State, county, pipeline name or number, pipe diameter, MAOP, wall thickness, pipe grade/strength, seam type, Class 1 **or Class 2** to Class 3 location change date, segment length, pipeline location by both ~~GIS~~ **GPS** coordinates and pipeline system survey stations or mile posts for the starting and ending points of the ~~Class 1 to~~ Class 3 location **change** segment~~, and the date of the Class 1 to Class 3 location change~~.

[. . .]

§192.3 Definitions.

[. . .]

~~*Class 1 to*~~ *Class 3 location* ***change*** *segment* means a pipeline segment where (1) the segment has changed from a Class 1 **or Class 2** to a Class 3 location; and (2) the operator is confirming or revising the maximum allowable operating pressure per § 192.611(a)(4). At the operator's discretion, the endpoints of the ~~Class 1 to~~ Class 3 location **change** segment may extend further than the beginning and endpoints of the Class 3 location involved.

[. . .]

In-line inspection segment means all pipe ~~within a Class 1 to Class 3 location segment and all pipe adjacent to the Class 1 to Class 3 location segment~~ between the nearest upstream in-line inspection launcher and the nearest downstream in-line inspection receiver.

[. . .]

Predicted failure pressure means the calculated pipeline anomaly failure pressure, based on the use of an appropriate engineering evaluation method for the type of anomaly being assessed, that does not have an **added** ~~included~~ safety factor. Different anomaly types (e.g., dent, crack, or metal loss) will require different engineering assessment or analysis methods to determine the predicted failure pressure.

[. . .]

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

[. . .]

(b) [. . .]

(12) API STANDARD 1163, "In-Line Inspection Systems Qualification," Second edition, April 2013, Reaffirmed August 2018, (API STD 1163), IBR approved for §§ 192.493, 192.618(b)(4), and (b)(4)(iii).

~~**(12)**~~ **API Recommended Practice 1183, "Assessment and Management of Dents in Pipelines," First edition, November 2020, (API RP 116=83), IBR approved for § 192.712.**

(c) [. . .]

(6) ASME/ANSI B31.8S-2004, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines," 2004, (ASME/ANSI B31.8S-2004), IBR approved for §§ 192.618; 192.903 note to *Potential impact radius*; 192.907 introductory text, (b); 192.911 introductory text, (i), (k), (*l*), (m); 192.913(a), (b), (c); 192.917 (a), (b), (c), (d), (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b), (c); 192.929(b); 192.933(c), (d); 192.935 (a), (b); 192.937(c); 192.939(a); and 192.945(a).

[. . .]

§ 192.18 How to notify PHMSA.

[. . .]

(c) Unless otherwise specified, if the notification is made pursuant to §192.506(b), §192.607(e)(4), §192.607(e)(5), **§192.618**, §192.624(c)(2)(iii), §192.624(c)(6), §192.632(b)(3), §192.710(c)(7), §192.712(d)(3)(iv), §192.712(e)(2)(i)(E), §192.921(a)(7), or §192.937(c)(7) to use a different integrity assessment method, analytical method, sampling approach, or technique (*i.e.,* "other technology") that differs from that prescribed in those sections, the operator must notify PHMSA at least 90 days in advance of using the other technology. An operator may proceed to use the other technology 91 days after submittal of the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposed use of other technology or that PHMSA requires additional time to conduct its review.

[. . .]

§192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours:

(i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per §192.620, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(3) The segment involved must be tested in accordance with the applicable requirements of subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(iii) For pipeline operating at an alternative maximum allowable operating pressure per §192.620, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(4) A ~~Class 1 to~~ Class 3 location **change** segment may have its maximum allowable operating pressure confirmed or revised in accordance with § 192.618.

(b) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the **change in class location** ~~**confirmation or revision**~~.

(c) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§192.553 and 192.555.

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §192.609 must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a) (1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section or implementing an integrity assessment program that meets paragraph (a)(4) of this section at a later date. The activities required in paragraphs (a)(3) or (a)(4) of this section must be implemented prior to any future increases of maximum allowable operating pressure to meet paragraphs (a)(1) or (a)(2) of this section.

[. . .]

§ 192.618 ~~Class 1 to~~ Class 3 location change segment requirements.

A ~~Class 1 to~~ Class 3 location **change** segment **operated in accordance with § 192.611(a)(4)** must meet the following requirements:

(a) *Program requirements for a ~~Class 1 to~~ Class 3 location* ***change*** *segment.* For segments that change from a Class 1 **or Class 2** to a Class 3 location, the maximum allowable operating pressure (MAOP) must be confirmed or revised by designating the segment involved as a high consequence area, as defined in § 192.903, and including it in an integrity management program in accordance with subpart O of this part, if the following criteria are met:

~~**(1) *Timing of Class 1 to Class 3 location change.* The Class 1 to Class 3 location segment change must have occurred after [INSERT THE EFFECTIVE DATE OF RULE]. An operator must conduct a class location study on the in-line inspection segment at least once each calendar year, with intervals not to exceed 15 months, in accordance with § 192.609. An operator must maintain its in-line inspection segment change in class location study records in accordance with paragraph (h) of this section.**~~

(2) *In-line inspection.* The in-line inspection segment must be assessed using instrumented in-line inspection tools that meet the requirements of paragraph (b)(1) of this section.

(3) *Hoop stress of ~~Class 1 to~~ Class 3 location change segment.* The hoop stress corresponding to the MAOP of a ~~the~~ Class 1 design factor pipe segment operated in accordance with § 192.611(a)(4) ~~to Class 3 location segment~~ must not exceed 72 percent of SMYS in Class 3 locations. The hoop stress corresponding to the MAOP of a Class 2 design factor pipe segment operated in accordance with § 192.611(a)(4) must not exceed 60 percent of SMYS in Class 3 locations.

(4) *Pipe attributes for review*. Pipeline segments with any of the following attributes cannot be a ~~Class 1 to~~ Class 3 location change segment:

(i) Bare pipe;

(ii) Pipe with wrinkle bends in the presence of unmitigated outside force threats;

(iii) Pipe that does not have traceable, verifiable, and complete pipe material records for diameter, wall thickness, grade, seam type, and yield strength~~, and tensile strength,~~ unless those attributes are verified within 24 months after the change to a Class 3 location segment;

(iv) Pipe that is uprated in accordance with subpart K, ~~(~~unless the segment passes a subpart J pressure test for a minimum of 8 hours at a minimum pressure of 1.39 times MAOP ~~within 24 months after the Class 1 to Class 3 location segment change and~~ prior to uprating or increasing the current MAOP~~)~~;

(v) Pipe that has not been pressure tested in accordance with subpart J ~~for 8 hours~~ at a minimum test pressure of 1.25 times MAOP (unless the segment passes a subpart J pressure test ~~for a minimum of 8 hours~~ at a minimum pressure of 1.25 times MAOP within 24 months after the change to a ~~Class 1 to~~ Class 3 location segment ~~change~~);

(vi) Pipe with direct current (DC), ~~low frequency electric resistance welded (LF-ERW), electric flash welded (EFW),~~ or lap-welded seams, ~~or~~ pipe with a longitudinal joint factor below 1.0, pipe with low frequency electric resistance welded (LF-ERW) seams on a pipe segment that is susceptible to significant cyclic fatigue, or pipe segments with LF-ERW or electric flash welded (EFW) seams that have had seam leaks or ruptures since the last successful pressure test in accordance with subparagraph (v); or

(vii) Pipe with unremediated cracking in the pipe body, seam, or girth welds in or within 5 miles of the ~~Class 1 to~~ Class 3 location change segment that: is over 20 percent of the pipe wall thickness, has a predicted failure pressure less than 100 percent of SMYS, has a predicted failure pressure less than 1.39 ~~1.50~~ times MAOP on class 1 design factor pipe or 1.50 times MAOP on class 2 design factor pipe, has resulted in ~~experienced~~ a leak or a rupture ~~due to pipe cracking~~, or for which analysis in accordance with paragraph (e) of this section indicates the pipe could fail in brittle mode.

(viii) ~~Poor~~ Pipe without effective external coating, as defined in § 192.457 and based on an evaluation conducted in accordance with the operator's procedures, ~~that requires a minimum negative cathodic polarization voltage shift of 100 millivolts or linear anodes along the Class 1 to Class 3 location segment to maintain cathodic protection in accordance with § 192.463, or a Class 1 to Class 3 location segment with~~ or pipe with tape wraps or shrink sleeves for which the operator has experienced a history of shielding pipe from cathodic protection.

(ix) Pipe that normally transports gas whose composition quality creates an internal corrosion threat ~~is not suitable for sale to gas distribution customers~~, including, but not limited to, pipe with free-flowing water ~~or hydrocarbons~~, water vapor content exceeding acceptable limits for gas distribution customer delivery, hydrogen sulfide (H_2S) greater than one grain per 100 cubic feet, or carbon dioxide (CO_2) greater than 3 percent by volume.

(x) Pipelines operating in accordance with § 192.619 (c) or (d).

(xi) A ~~**Class 1 to**~~ Class 3 location **change** segment~~**, in-line inspection segment,**~~ or portion of it that has been previously denied by the special permit process in § 190.341.

(b) *Pipeline integrity assessments.* In addition to the requirements specified in subpart O of this part, pipeline integrity assessments for the in-line inspection segment, including the ~~**Class 1 to**~~ Class 3 location **change** segment, must meet the following:

(1) *Assessment method*. Operators must perform pipeline assessments using the following in-line inspection tools or alternative methods as applicable for the pipeline integrity threats **to which the Class 3 location change segment is susceptible** ~~**being assessed**~~:

(i) In-line inspection with a high-resolution magnetic flux leakage (HR-MFL) tool or an equivalent internal inspection device;

(ii) In-line inspection with a high-resolution deformation tool (HR-Deformation), with sensors and extension arms outside the tool cups, or an equivalent internal inspection device;

(iii) In-line inspection with an electromagnetic acoustic transducer (EMAT) tool or an equivalent internal inspection device;

(iv) In-line inspection with an inertial measurement unit (IMU) tool or an equivalent internal inspection device;

(v) An operator may use alternative methods, such as pressure testing or other technology ~~**(excluding direct assessment)**~~, upon submitting a notification to PHMSA 90 days prior to using the alternative method, in accordance with § 192.18.

(vi) If an operator chooses not to conduct the in-line inspection as required in paragraphs (iii) or (iv) on a pipeline segment with a history of pipe body or weld cracking or pipe movement, then the operator must notify PHMSA in accordance with § 192.18.

(2) *Initial assessment.* Within 24 months of the **change to a** ~~**Class 1 to**~~ Class 3 location segment ~~**change**~~, an operator must identify and document each integrity threat to which the **Class 3 location change** ~~**pipeline**~~ segment is susceptible and conduct initial pipeline integrity assessments of the entire in-line inspection segment for each threat **to which the Class 3 location change segment is susceptible** in accordance with §§ 192.917, 192.921, and paragraph (b)(1) of this section. **An operator may use a prior assessment conducted before the class change as an initial assessment for the pipeline segment, if the assessment met the requirements of part 192 for in-line inspection at the time of the assessment. If an operator uses a prior assessment as its initial assessment, the operator must:**

(i) Remediate anomalies in accordance with 192.618(c) within 24 months of the change to a Class 3 location; and

(ii) Reassess the pipeline segment according to the reassessment interval specified in paragraph (b)(3) of this section calculated from the date of the prior assessment.

(3) *Reassessments*. The operator must conduct periodic reassessments in accordance with § 192.937 and paragraph (b)(1) of this section at least once every 7 calendar years, with intervals not to exceed 90 months, ~~as~~ specified in § 192.939(a).

(4) *In-line Inspection Validation*. Operators must validate the results of all in-line inspections, for each type in-line inspection tool run conducted in accordance with this section, ~~**to Level 3 standards**~~ in accordance with API Standard 1163 (incorporated by reference, *see* § 192.7) **and based on the availability of anomaly validation data pursuant to subparagraph (ii)**.

(i) An operator must analyze and account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) when identifying and characterizing anomalies.

(ii) For each threat type assessed by ILI tool type, an operator must validate the in-line inspection tool tolerance for each in-line inspection tool run using **API 1163 validation methodology** ~~a minimum of 4 anomaly validations~~ or 100 percent of anomalies, whichever **requires fewer validation excavations** ~~**is less**~~, either from new excavations or from past excavations in the in-line inspection segment, with documented anomaly dimensions (width, depth, length, and location) or other known pipe features that are appropriate for the in-line inspection tool.

(iii) For pipeline areas of metal loss where in-line inspection tool data for anomaly size and characterization are used in the determination of the predicted anomaly failure pressure, an operator must use Section 6.2.3, Table 1 – Characterizing Metal Loss Probabilities of Detection - Depth Detection Threshold, in accordance with API Standard 1163 (incorporated by reference, *see* § 192.7). Using the qualifiers and limitation criteria in Section 6.2.3, Table 1 of API Standard 1163 or technically proven criteria appropriate for the location, size, and type of the anomaly, an operator must evaluate the anomaly based on whether it is an extended metal loss, pit, or groove.

(iv) An operator may use alternative methods for in-line inspection tool verification, such as calibration joints near the upstream and downstream ILI tool launchers and receivers, upon submitting a notification to PHMSA 90 days prior to using the alternative method, in accordance with § 192.18.

(5) *Discovery of condition*. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under § 192.933 and paragraphs (c), (d), and (e) of this section. An operator must promptly, but no later than 180 days after conducting a pipeline integrity assessment **for high consequence area segments, including the Class 3 location change segment, and 240 days for all other pipe segments**, obtain sufficient information about a condition to make such a determination of an integrity threat that requires remediation.

(c) *Remediation schedule (In-line inspection segment)*. In addition to the requirements specified in subpart O of this part, **where applicable,** remediation for the in-line inspection segment, including the ~~**Class 1 to**~~ Class 3 location **change** segment, must meet the following:

(1) *Immediate ~~repair~~ conditions*. An operator must **remediate** ~~**repair**~~ the following conditions immediately upon discovery:

(i) Metal loss anomalies where the calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with § 192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.

(ii) Metal loss greater than 80 percent of nominal wall, regardless of dimensions.

(iii) Metal loss preferentially affecting a detected longitudinal seam and where the predicted failure pressure determined in accordance with § 192.712(d) is less than or equal to 1.25 times the MAOP.

(iv) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless a technically proven engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded before the next engineering analysis or assessment is conducted.

(v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

(B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.

(vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

(2) ~~***One -year***~~ ***Scheduled*** *conditions*. An operator must **remediate** ~~**repair**~~ the following conditions within 1 year of discovery **inside high consequence area segments, including the Class 3 location change segment, and within 2 years of discovery for all other pipe segments**:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded before the next engineering analysis or assessment is conducted.

(ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded before the next engineering analysis or assessment is conducted.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded before the next engineering analysis or assessment is conducted.

(iv) Metal loss anomalies where a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with § 192.712(b), at the location of the anomaly less than or equal to 1.39 times the MAOP for Class 2 locations, and 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations outside the ~~Class 1 to~~ Class 3 location change segment with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, figure 4. For Class 1 pipe within the ~~Class 1 to~~ Class 3 location change segment, a metal loss anomaly with a predicted failure pressure of less than or equal to 1.39 times the MAOP.

(v) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, with a predicted failure pressure determined in accordance with § 192.712(b) less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and ~~all~~ Class 3 and Class 4 locations. For Class 1 pipe within the ~~Class 1 to~~ Class 3 location change segment, metal loss with a predicted failure pressure of less than or equal to 1.39 times the MAOP.

(vi) Metal loss preferentially affecting a detected longitudinal seam and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and ~~all~~ Class 3 and Class 4 locations. For Class 1 pipe within the ~~Class 1 to~~ Class 3 location change segment, metal loss with a predicted failure pressure of less than or equal to 1.39 times the MAOP.

(vii) A crack or crack-like anomaly that has a predicted failure pressure determined in accordance with § 192.712(d) that is less than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and ~~all~~ Class 3 and Class 4 locations. For Class 1 pipe within the ~~Class 1 to~~ Class 3 location change segment, a crack or crack-like anomaly with a predicted failure pressure of less than or equal to 1.39 times the MAOP.

~~(3) *Remediation schedule (Class 1 to Class 3 location segment)*. In addition to the requirements in paragraph (e) of this section, remediation for the Class 1 to Class 3 location segment must meet the following:~~

~~(i) *One-year condition*. An operator must repair the following conditions within 1 year of discovery:~~

~~(A) Pipe wall thickness loss greater than 40 percent.~~

~~(B) A crack with depth greater than 40 percent of the pipe wall thickness.~~

~~(4) *Two-year condition for crack (in-line inspection segment)*. An operator must repair the following condition within 2 years of discovery:~~

~~(i) A crack or crack-like anomaly that has a predicted failure pressure determined in accordance with § 192.712(d) that is greater than or equal to 1.39 times MAOP, and the crack depth is less than or equal to 40 percent of the pipe wall thickness~~.

(5) *Monitored condition*. An operator does not have to schedule the following conditions for remediation but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored conditions are the least severe and will not require examination and evaluation until the next scheduled integrity assessment interval~~, provided an analysis shows they are not expected to grow to dimensions meeting a 1-year condition prior to the next scheduled assessment~~. Monitored conditions are:

(i) A dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe);

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and an engineering analysis conducted in accordance with § 192.712(c) demonstrate that critical strain levels on the dent will not be exceeded;

(iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels on the dent and girth or seam weld will not be exceeded;

(iv) A dent that has metal loss, cracking, or a stress riser, and an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded;

(v) Metal loss preferentially affecting a detected longitudinal seam and where the predicted failure pressure determined in accordance with § 192.712(d) is greater than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and ~~all~~ Class 3 and Class 4 locations. For Class 1 pipe within the ~~Class 1 to~~ Class 3 location **change** segment, metal loss with a predicted failure pressure ~~of less~~ **greater** than or equal to 1.39 times the MAOP; and

(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and ~~all~~ Class 3 and Class 4 locations. For Class 1 pipe within the ~~Class 1 to~~ Class 3 location **change** segment, a crack or crack-like anomaly with a predicted failure pressure greater than 1.39 times the MAOP.

(d) *Special requirements for crack anomalies*. If cracks are discovered in the ~~Class 1 to~~ Class 3 location **change** segment that meet the criteria in paragraph (a)(4)(vii) of this section, the operator must **submit a crack remediation and management plan to PHMSA within 90 days in accordance with § 192.18. The plan must include characterization of crack anomalies, timing for remediation, and a technical justification that the operator is addressing the threat of cracking in the Class 3 location change segment.** ~~implement the requirements in § 192.611(a)(1), (a)(2), or (a)(3) within 2 years. Until the pipe is replaced, operators must remediate cracks as specified in paragraph (c) of this section.~~

(e) *Pipe and weld cracking inspections*. Except for pipe coated with fusion-bonded or liquid-applied epoxy coatings and excavations performed in accordance with § 192.614(c), an operator must inspect any pipe in the in-line inspection segment, including the ~~Class 1 to~~ Class 3 location **change** segment, that is uncovered for any reason to evaluate the pipe for cracking where the coating is removed. An operator must use non-destructive examination methods and procedures appropriate for the type of non-destructive examination method, and for the type of pipe and integrity threat conditions in the ditch. If an operator finds any cracking, the operator must conduct an analysis in accordance with § 192.712 and remediate anomalies in accordance with paragraphs (c) and (d) of this section.

(f) *Additional preventive and mitigative measures.* For a ~~Class 1 to~~ Class 3 location **change** segment, an operator must conduct the following operations and maintenance actions and surveys within 2 years of the **change to a** ~~Class 1 to~~ Class 3 location segment ~~**change**~~, evaluate the findings, and remediate as follows:

(1) Close interval surveys with an "on and off" current at a maximum 5-foot spacing. An operator must evaluate in accordance with § 192.463 and remediate the unprotected pipe segments within 1 year of the survey. Operators must conduct close interval surveys on reassessment intervals of at least once every 7 calendar years, with intervals not to exceed 90 months. **An operator may use a prior close interval survey conducted before the class change as an initial survey for the class location change segment. If an operator uses this prior survey as its initial survey, the operator must reassess the pipeline segment according to the reassessment interval specified in this paragraph the date of the prior survey.**

(2) At least 1 cathodic protection pipe-to-soil test station must be located within the ~~Class 1 to~~ Class 3 location **change** segment with a maximum spacing of ½ mile between test stations. In cases where obstructions or restricted areas prevent test station placement, the test station must be placed in the closest practical location. Annual monitoring of the cathodic protection pipe-to-soil test stations must meet §§ 192.463 and 192.465 for the ~~Class 1 to~~ Class 3 location **change** segment.

(3) Install and maintain line-of-sight markers visible on the pipeline right-of-way, except in agricultural areas or large water crossings, such as lakes, where line-of-sight markers are not practical. An operator must replace line-of-sight markers as necessary and within 30 days after identifying a missing line-of-sight marker.

(4) Interference surveys to address induced alternating current (AC) from parallel electric transmission lines, and other interference issues, such as direct current (DC), that may affect the ~~Class 1 to~~ Class 3 location **change** segment. If an interference survey finds the interference current is greater than or equal to 100 amps per meter squared, impedes the safe operation of a pipeline, or may cause a condition that would adversely impact the environment or public safety, an operator must correct these instances within 15 months of the interference survey. **An operator may use a prior interference survey conducted before the class change as an initial survey for the class location change segment.**

(5) Depth of cover must conform with § 192.327 for a ~~Class 1 to~~ Class 3 location **change** segment or be remediated by adding markers at locations that do not meet the requirements of § 192.327 for a Class 1 location, lowering the pipe, adding cover, or installing safety barriers. ~~**Where the depth of cover is less than 24 inches in areas of non-consolidated rock, the operator must either lower the pipe or add cover over the Class 3 location segment.**~~

(6) Right-of-way patrols in accordance with paragraphs (a) and (c) of § 192.705 at least once per month, with intervals not to exceed 45 days for ~~Class 1 to~~ Class 3 location **change** segment.

(7) Leakage surveys at intervals not exceeding 4½ months, but at least four times each calendar year for **the** ~~Class 1 to~~ Class 3 location **change** segment.

(8) For shorted casings in **the** ~~Class 1 to~~ Class 3 location **change** segment, operators must **attempt to** clear the metallic short no later than 1 year after the short is identified, **if the attempt can be performed safely.** For an electrolytic casing short, operators must remove the electrolyte from the casing/pipe annular space no later than 1 year after the short is identified. **If it is impractical or unsafe to clear a metallic short or**

remove the electrolyte from an electrolytic short, the operator must take other preventative and mitigative corrosion control measures, such as monitoring with inline inspection tools that have been demonstrated to properly detect and assess corrosion and remediating any actionable anomalies in accordance with subsection (c).

(9) Preventative and mitigative conducted in accordance with this subsection qualify as "additional measures beyond those already required by Part 192" for purposes of complying with § 192.935(a).

(g) *Remote-control or automatic shutoff valves*. Mainline valves on both sides of **the** ~~**Class 1 to**~~ Class 3 location **change** segment, and isolation valves on any crossover or lateral pipe designed to isolate a leak or rupture in a ~~**Class 1 to**~~ Class 3 location **change** segment, must be operational remote-controlled or automatic shutoff valves with pressure sensors on each side of the mainline valves. The maximum distance between such mainline valves must not exceed 20 miles.

(1) Valves installed in accordance with this paragraph must be closed as soon as practicable after a rupture is identified, but not to exceed 30 minutes.

(2) Valves installed in accordance with this paragraph must be operational at all times~~**, controlled by a SCADA system,**~~ and monitored in accordance with § 192.631.

(3) Valves installed in accordance with this paragraph must be maintained in accordance with §§ 192.631(c)(2) and (c)(3), and 192.745.

(4) Automatic shutoff valves installed in accordance with this paragraph must be set so that, based on operating conditions and minimum and maximum flow model gradients, they will fully close within a maximum of 30 minutes following rupture identification. Automatic shutoff valve set-points must not be less than those required to actuate the valve before a downstream remote-control valve actuates. The automatic shutoff valve procedure and results for determining shutoff times must be reviewed for accuracy at least once each calendar year, with intervals not to exceed 15 months.

(h) *Documentation*. In addition to the documentation requirements specified in § 192.947, each operator must maintain records of all actions implemented to comply with paragraph (e) of this section for the life of the pipeline, including but not limited to subpart J pressure test records in accordance with § 192.517; and records of any pipeline assessments, surveys, remediations, maintenance, analyses, and other implemented actions. **An operator must also maintain records of any change in class location studies conducted on the in-line inspection segment in accordance with § 192.609 for the life of the pipeline.**

(i) *Notifications to PHMSA of integrity assessment program for* ~~***class 1 to***~~ *class 3 location segment changes.* Each operator of a gas transmission pipeline that uses the integrity assessment program option for managing a ~~**Class 1 to**~~ Class 3 location **change** segment ~~**change**~~ must notify PHMSA electronically in accordance with § 191.22(c)(2).

[. . .]

§192.712 Analysis of predicted failure pressure.

[. . .]

(c) *Dents*. To evaluate dents and other mechanical damage that could result in a stress riser, an operator must perform an engineering critical assessment **in accordance with API RP 1183**, as follows:

(1) Evaluate potential threats for the pipe segment in the vicinity of the anomaly or defect including movement, external loading, cracking, and corrosion;

(2) Review high-resolution magnetic flux leakage (HR-MFL) and high-resolution deformation inline inspection data for damage in the dent area and any associated weld region;

(3) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data;

(4) Compare the dent profile between the most recent and previous in-line inspections to identify significant changes in dent depth and shape;

(5) Identify and quantify all significant loads acting on the dent;

(6) Evaluate the strain level associated with the anomaly or defect and any nearby welds using Finite Element Analysis, or another technology ~~in accordance with paragraph (c)(8) of this section~~;

(7) The analyses performed in accordance with this section must account for material property uncertainties and model inaccuracies and tolerances;

(8) Dents with geometric strain levels that exceed the critical strain must be remediated in accordance with § 192.713 or § 192.933, as applicable;

(9) Using operational pressure data, **demonstrate that potential for fatigue damage does not exist. If potential for damage due to fatigue is present, using** a valid fatigue life prediction model, and assuming a reassessment safety factor of 2, estimate the fatigue life of the dent by Finite Element Analysis or other analytical technique in accordance with this section.

~~(10) An operator using other technologies or techniques to comply with paragraph (c) of this section must submit advance notification to PHMSA in accordance with § 192.18.~~

[. . .]

§192.903 What definitions apply to this subpart?

The following definitions apply to this subpart:

[. . .]

High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

(i) A Class 3 location under §192.5; or

(ii) A Class 4 location under §192.5; or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

(v) Any ~~Class 1 to~~ Class 3 location **change** segment designated as a high consequence area in accordance with § 192.618(a).

(2) The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

(ii) An identified site; or

(iii) Any ~~Class 1 to~~ Class 3 location **change** segment designated as a high consequence area in accordance with § 192.618(a).

(3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See figure E.I.A. in appendix E.)

(4) If in identifying a high consequence area under paragraph (1)(iii) of this definition or paragraph (2)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy with a distance of 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (*i.e.*, the prorated number of buildings intended for human occupancy is equal to 20 × (660 feet) [or 200 meters]/potential impact radius in feet [or meters]^2).

[. . .]