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 ON PIPELINE SAFETY: CLASS LOCATION CHANGE REQUIREMENTS

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I. Introduction & Executive Summary

The American Gas Association (AGA)[1], American Petroleum Institute (API)[2], American Public Gas Association (APGA)[3] and Interstate Natural Gas Association of America (INGAA)[4] (jointly "the Associations") submit these comments for consideration by the Pipeline and Hazardous Materials Safety Administration (PHMSA) concerning the "Pipeline Safety: Class Location Change Requirements" Advance Notice of Proposed Rulemaking (ANPRM).

Pipeline safety is the top priority of the Associations and our members. The Associations strongly support regulations that advance improvements in pipeline safety practices and that embrace modern integrity assessment processes and technologies, with the intent of achieving a perfect safety and reliability record for our nation's natural gas pipeline network. The Associations commend PHMSA for taking steps, through the ANPRM, to update the obsolete regulations governing class location changes for natural gas transmission pipelines.[5] There have been dramatic engineering and technological advances since the class location change regulations were issued in 1970, and the ANPRM represents an important opportunity to promote the continued deployment of modern integrity assessment technologies.

PHMSA should modernize its class location regulations by providing an integrity assessment option for managing natural gas transmission pipeline class location changes. Such an approach would leverage modern technologies and processes for evaluating actual pipe condition to confirm the integrity of the class change segment and target any repairs and replacements as appropriate. The specific purpose of the class location change requirements, to ensure an appropriate safety margin when population growth occurs around an existing pipeline, remains unchanged from when the rules first were adopted in 1970. This objective can now be accomplished using modern integrity assessment programs, which are a more effective, more efficient and less disruptive means of managing pipeline safety. Many stakeholders –

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

[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 700 members in 37 states. Overall, there are nearly 1,000 municipally-owned systems in the U.S. serving more than five million customers. Publicly-owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

[4] INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 28 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.

[5] 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.

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 assessment programs over the last several decades. It is because of today's integrity assessment processes and technologies that class location changes no longer present the risk that they may have in the past.

The Associations' interest in an integrity assessment option for managing class changes is not about saving money – rather, it's about seizing an opportunity to allocate resources towards technologies and processes that will do the most to enhance pipeline safety. Furthermore, the construction activities necessitated by pipe replacements can cause unnecessary land disturbances, impact deliveries to consumers, result in releases of natural gas into the atmosphere and needlessly disrupt nearby landowners and communities. Instead, modern integrity assessment programs can be used to confirm pipeline integrity or identify locations where pipe condition actually warrants replacement, thereby minimizing the arbitrary replacement of pipe that is in safe, operable condition.

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. The opportunity to invest resources in integrity assessment programs instead will promote the expansion of modern pipeline safety processes and technologies and therefore will be a significant step in the pursuit of perfect safety performance.

For example, for $250 million, the Associations estimate that pipeline operators would be able to make less than 75 miles of class location change pipe replacements. Alternatively, operators could assess over 25,000 miles with in-line inspection, install launchers and receivers to enable over 5,000 miles of pipeline to be assessed with in-line inspection tools for the first time, or conduct over 4,000 anomaly evaluation digs. These examples illustrate how investment in, and utilization of, modern integrity assessment 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.

Therefore, there is an immediate opportunity to promote pipeline safety by aligning the class location change requirements with modern integrity assessment programs. PHMSA should develop an integrity assessment option for managing class location changes that follows the direction taken in its pending "Safety of Gas Transmission and Gathering Pipelines" regulations (2016 Proposed Gas Transmission Integrity Rules).[6,7] Conducting integrity assessments for all threats that are relevant to a particular pipe segment and repairing or replacing pipe as required based on its condition will achieve the purpose of the class location change regulations.

For class location change segments managed in accordance with the integrity assessment option, operators should be required to implement the integrity assessment program requirements in the 2016 Proposed Gas Transmission Integrity Rules on an expedited basis. The Associations recommend that initial integrity assessments be required within two years of identifying the class location change. This is consistent with the timeframe required under the current class location change regulations.

[6] Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. 36,861 (July 31, 2018).

[7] When the Associations reference the "2016 Proposed Gas Transmission Integrity Rules" in this document, the reference is to the NPRM, as modified by the Gas Pipeline Advisory Committee.

The Associations strongly support the 2016 Proposed Gas Transmission Integrity Rules, with the revisions endorsed by the Gas Pipeline Advisory Committee (GPAC). The 2016 Proposed Gas Transmission Integrity Rules will enhance and expand, to many new areas, the application of integrity assessment programs that have been part of PHMSA's regulations for almost 15 years. These regulations provide comprehensive requirements that guide how operators employ modern pipeline assessment technologies. The 2016 Proposed Gas Transmission Integrity Rules have been reviewed by PHMSA's GPAC over the past two years and enjoy broad support from public, federal, state and industry representatives. These proposed rules will establish gas transmission pipeline safety objectives for at least the next two decades. PHMSA should now align the class location change regulations with the direction of the broader pipeline safety program. The 2011 reauthorization of the Pipeline Safety Act directed PHMSA to consider this update to the class location change regulations.[8]

It is not necessary for PHMSA to develop brand new, unique integrity management processes for class location changes. This would be counterproductive, because it is likely that the deployment of modern integrity assessment technologies would be hindered while operators wait years for PHMSA to complete yet another protracted rulemaking.

Integrity assessments for class change segments should be conducted in accordance with the 2016 Proposed Gas Transmission Integrity Rules and operators should be required to utilize specific modern internal inspection technologies, as further detailed in these comments. A technology-based integrity assessment method for managing class location changes will promote more tailored solutions and investments in projects that will do the most to ensure pipeline safety. Specifically, this new option for managing class location changes will:

- Spur further deployment of modern internal inspection technologies;
- Incentivize operators to modify more pipe segments to allow internal inspections;
- Maximize the benefit of the 2016 Proposed Gas Transmission Integrity Rules and encourage early adoption;
- Avoid unnecessary pipe replacements and the associated construction activities, which can cause land disturbances, impact deliveries to consumers, result in releases of natural gas into the atmosphere and needlessly disrupt nearby landowners and communities;
- Promote continuous development of new and improved assessment tools; and
- Reduce the need for PHMSA staff to process individual special permit requests.

[8] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Pub. L. No. 112-90. § 5, 125 Stat. 1904, 1907.

II. Background: Development of Modern Integrity Assessment Programs

The time is right for PHMSA to allow for an integrity assessment option for managing class location changes. There have been dramatic engineering and technological advances since the class location design standards were developed in the 1950s,[9] since the class location change regulations were first issued in 1970,[10] and even since the Gas Transmission Integrity Management regulations were promulgated in 2003.[11] Despite these pivotal improvements, the class location change regulations have never been substantively revised. Because of integrity assessment processes and technologies, class location changes no longer present the unique risk that they may have in the 1950s.

The 2016 Proposed Gas Transmission Integrity Rules will enhance the existing integrity assessment requirements and apply them to a much larger proportion of the transmission pipeline system.[12] Integrity assessment programs were initially required for gas transmission pipelines in high consequence areas in the early 2000s.[13] Over the last two decades, PHMSA and transmission pipeline operators have demonstrated the value of technology-based assessment programs for managing pipeline integrity. Technology-based integrity programs use established assessment tools to evaluate actual pipe condition and target further action accordingly. Modern integrity assessment programs often rely on internal inspection technologies, particularly for long-haul transmission pipeline systems.[14] A variety of in-line inspection (ILI) tools exist today, which have the capability to detect, characterize and size an array of pipeline anomalies, including corrosion, cracking, dents and seam issues.

In-line inspection tool capabilities have dramatically improved over the last several decades.

ILI tools have revolutionized pipeline inspections. The early 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,

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[9] American Society of Mechanical Engineers (ASME), ASA B31.1.8 Gas Transmission and Distribution Piping Systems, 1955.

[10] Establishment of Minimum Standards, 35 Fed. Reg. 13,248, 13,251 (Aug. 19, 1970).

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

[12] "Pipeline Safety: Safety of Gas Transmission Pipelines, MAOP Reconfirmation, Expansion of Assessment Requirements and Other Related Amendments" and "Pipeline Safety: Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments."

[13] *Id.*

[14] For a brief review of historical, present and future ILI capabilities, *see*: Rau J, Kirkwood M. Hydrotesting and In-Line Inspection: Now and in the Future. ASME. International Pipeline Conference, Volume 1: Pipelines and Facilities Integrity ():V001T03A055. doi:10.1115/IPC2016-64105.

ILI providers have begun to combine technologies into single "combo" tools to enable detection of a variety of anomalies in one run.[15]

Furthermore, tool capabilities in traversing difficult and low pressure/low flow pipelines have greatly improved in recent years. Today, many pipeline segments can be internally inspected where it was not possible to do so in the past. For example, ILI tools historically have had limited capability to traverse pipelines with significant diameter changes. Now, several tools are able to negotiate up to 25% changes in diameter.

Pipeline operators continually learn from the results of integrity assessment programs to enhance the safety of their entire pipeline network. Operators periodically review actionable anomalies that were identified through ILI assessment and then excavated for further examination. If the operator determines that a particular tool is systematically over-or under-calling anomalies, the operator works with the provider to correct those issues. This type of continual improvement process is formalized in API RP 1163: *In-line Inspection Systems Qualification.* The 2016 Proposed Gas Transmission Integrity Rules will require operators to implement RP 1163, per proposed § 192.493.[16]

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 and data management capabilities over the last several decades.

PHMSA has positioned integrity assessment as central to modern gas transmission pipeline safety. It is the right time to allow integrity assessment programs to manage class location changes.

The Research and Special Programs Administration (PHMSA's predecessor) completed the first rulemaking to require integrity assessment programs for gas transmission pipelines in high consequence areas in 2003.[17] 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."[18] There has now been almost fifteen years' experience to use as a basis for determining how best to harmonize class location changes with integrity assessment programs.

As a result of advancements in engineering and technology, proven processes now exist for managing an array of pipeline integrity threats and risk factors, many of which were originally piloted as part of class location change special permits. PHMSA has incorporated these new processes into the 2016 Proposed Gas Transmission Integrity Rules, which enhance and expand integrity assessment requirements. These pending integrity regulations have been publicly vetted through the GPAC process and have broad stakeholder support. Lessons learned from the first fifteen years of Integrity Management have been incorporated into these regulations. These regulations establish gas transmission pipeline safety

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[15] 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.
[16] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. at 20,830.
[17] Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines), 68 Fed. Reg. 69,778 (Dec. 15, 2003).
[18] *Id.* at 69,772.

objectives for at least the next 15-20 years, and PHMSA should create a regulatory option for managing class location changes that aligns with those objectives.

In the ANPRM, "PHMSA acknowledges that applying modern IM assessments and processes could potentially be a comparable alternative to pipe change-outs. PHMSA notes that if operators perform integrity assessments on significant portions of non-HCA pipe mileage, PHMSA could further consider operators using such assessments to determine whether pipe in a changed class location is fit for service rather than having to replace it."[19] The 2016 Proposed Gas Transmission Integrity Rules provide such requirements to perform integrity assessments outside of HCAs.

During prior public proceedings that 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.[20] The 2016 Proposed Gas Transmission Integrity Rules do exactly that.

Revising the antiquated class location change requirements to allow an integrity assessment method is long overdue. The enormous amount of resources that operators, state and federal regulators and public representatives have invested in developing, implementing and enhancing integrity assessment 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 integrity assessment programs – not pipe replacements.

[19] Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. at 36,868.

[20] 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.

III. Impacts of Current Class Location Change Regulations and Opportunities for Improvement

PHMSA's antiquated class location change requirements hinder the deployment of modern integrity assessment technologies and processes that will enhance pipeline safety.

As noted in the ANPRM, following a class location change, PHMSA's regulations allow operators to 1) use pressure testing to reconfirm the maximum allowable operating pressure (MAOP), 2) reduce operating pressure or 3) replace pipe. However, there are pipe design and regulatory limitations on an operator's ability to conduct a pressure test or rely on a previous test to manage a class location change (§ 192.611(a)(1) and (§ 192.611(a)(3)). Furthermore, although the regulations allow gas transmission operators to implement a pressure reduction commensurate with the new class location design factor (§ 192.611(a)(2)), taking this step can negatively impact the company's ability to serve its firm transportation customers that have entered into contractual agreements for a certain quantity of natural gas to meet their reliability and commercial needs. Due to the limitations on the pressure test-based options and the customer impacts of pressure reductions, pipe replacement is often the only practicable option allowed by current regulations to manage a class location change, particularly when a segment has experienced a two-class change (e.g., class 1 to class 3).

As an example, local gas distribution companies (LDCs), which contract with gas transmission pipelines to transport natural gas to their citygates, 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. Therefore, decreasing the MAOP on a gas transmission line often is not an acceptable solution. The Associations note that 95% of publicly-owned gas systems receive their natural gas from a single transmission pipeline. If, for any reason, 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.

While pipe replacement may be an operator's only practicable option that is allowed by the current regulations following a class location change, pipe replacements can be a poor allocation of resources when the operator can otherwise confirm through integrity assessment that the pipe is in safe, operable condition. The opportunity to invest additional resources in modern integrity assessment programs instead of pipeline replacements would be a significant step forward in the pursuit of perfect safety performance, as detailed below. Furthermore, construction activities necessitated by pipe replacements can cause unnecessary land disturbances, impact deliveries to consumers, result in releases of natural gas into the atmosphere through blowdowns and needlessly disrupt nearby landowners and communities. Performing construction activities on a safe, operable pipeline also introduces new, unnecessary risks to the pipeline system.

Lost opportunity to invest in modern technologies and processes

AGA, API and INGAA previously estimated that natural gas transmission pipeline operators incur annual costs of $200 – $300 million nationwide replacing pipe solely to satisfy the current class location change regulations.[21] In Section IV below (see **Table 2**), the Associations provide detailed historical data to support this estimate.

Despite the tremendous amount of resources being allocated to class location change pipe replacements, these replacements have limited safety benefit. The data in Table 2 indicates that despite the huge annual costs of replacing pipe due to the current class location change requirements, less than 75 miles of pipe are being replaced each year. Ultimately, the inordinate total pipe replacement costs result from class location changes requiring replacements of many small segments of pipe. Instead of these short pipe replacements, the regulations should allow pipeline operators to focus their finite resources on using the most effective integrity assessment processes and technologies to enhance the safety of their entire pipeline system.

For example, for $250 million, instead of replacing less than 75 miles of pipe, operators could assess over 25,000 miles with in-line inspection,[22] install launchers and receivers to enable over 5,000 miles of pipeline to be assessed with in-line inspection tools for the first time,[23] or conduct over 4,000 anomaly evaluation digs.[24] These examples illustrate how investment in, and utilization of, modern integrity assessment 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 system than replacing short pipe segments. Therefore, integrity assessment offer 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.[25] 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 assessment programs. While operators often voluntarily conduct integrity assessment program activities, resources will always be prioritized to meet mandatory requirements.

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

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[21] Comments of AGA, API and INGAA on the Department of Transportation Notification of Regulatory Review at 3, No. OST-2017-0069 (Nov. 9, 2017), https://www.regulations.gov/document?D=DOT-OST-2017-0069-1504.

[22] 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.

[23] 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.

[24] 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.

[25] 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.

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.

Providing an integrity assessment method for managing class location changes will allow pipelines to avoid unnecessarily replacing pipe, minimize disruptions, and allow resources to instead be invested in modern integrity management technologies and processes to enhance pipeline safety.

Natural gas releases

The Associations estimate that up to 800 million standard cubic feet of natural gas blowdowns to the atmosphere could be avoided each year if operators were able to employ integrity assessment technologies to manage class location changes, instead of initiating construction projects to replace pipe.[26] This volume of natural gas (800 million standard cubic feet) could meet the needs of over 10,000 homes for a year.[27] 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, even if mitigation measures are implemented.[28] Therefore, even with mitigation measures in place, an integrity assessment option for managing class location changes would likely significantly reduce the volume of natural gas released to the atmosphere.

Challenges with special permit process

The special permit process has provided a forum for operators and PHMSA to develop and demonstrate integrity assessment technologies and processes for managing class location changes. However, this "one-off" process is no longer the right tool, as it is clear that PHMSA and pipeline operators have gained confidence in integrity assessment technologies and processes over the last two decades. Codifying an integrity assessment option for class changes provides more certainty and consistency 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 three years from the

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[26] 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. Based on historical data for class location change pipe replacements (see **Table 2** in Section IV below), the Associations estimate that 185 separate segments are replaced each year due to class location changes. *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.

[27] *See* American Gas Association's *What Is Natural Gas?*, https://www.aga.org/natural-gas/energy-education/. "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.

[28] 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.

filing of the application to issuance of the permit.[29] Operators file special permit applications based on PHMSA's published "typical conditions,"[30] yet, in recent years, PHMSA has imposed additional requirements in special permits in addition to the typical conditions. This practice creates significant uncertainty for operators when assessing whether to invest the substantial resources required to draft a special permit application. The resources required to complete the special permit process itself often compels operators to proceed with construction activities to replace pipe that is in in safe, operable condition. Differing special permit requirements can also result in inconsistent interpretation by PHMSA personnel. Inconsistent interpretation is less likely to occur with a regulation, which goes through a rulemaking process designed to ensure clarity, consistency and alignment with other existing regulations.

Finally, the special permit renewal process presents significant risk 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 never have filed for the special permit in the first place. Similarly, PHMSA can rescind a special permit at any time. Operators would incur hundreds of millions of dollars in costs to replace all of the segments that are currently managed under class location change special permits.

These challenges are underscored by the fact that several class location change special permits have not been renewed. 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 assessment 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.

[29] Duke Energy 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).

[30] 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.

IV. Response to PHMSA's ANPRM Questions

A. PHMSA should allow an integrity assessment option for managing class location changes.

Q1 - When the population increases along a pipeline route that requires a class location change as defined at § 192.5, should PHMSA allow pipe integrity upgrades from Class 1 to Class 3 locations by methods other than pipe replacement or special permits? Why or why not?

Q1a. – Should part 192 continue to require pipe integrity upgrades when class locations change from Class 1 to Class 3 locations or Class 2 to 4 locations? Why or why not?

Q1b. – Should part 192 continue to require pipe integrity upgrades from Class 1 to Class 3 locations for the "cluster rule" (see § 192.5(c)) when 10 or fewer buildings intended for human occupancy have been constructed along the pipeline segment? Why or why not?

Q2 – Should PHMSA give operators the option of performing certain IM measures in lieu of the existing measures (pipe replacement, lower the operating pressure, or pressure test at a higher pressure; see § 192.611) when class locations change from Class 1 to Class 3 due to population growth within the sliding mile? Why or why not?

Q3 – Should PHMSA give operators the option of performing certain IM measures in lieu of the existing measures (pipe replacement with a more conservative design safety factor or a combination of pressure test and lower MAOP) when class locations change due to additional structures being built outside of clustered areas within the sliding mile, if operators are using the cluster adjustment to class locations per § 192.5(c)(2)? Why or why not?

PHMSA should allow an *integrity assessment option* for managing class location changes for all of the class location change scenarios described in the above questions.

The current class location change requirements are outdated and hinder the deployment of modern technologies and processes that will enhance pipeline safety. The 2016 Proposed Gas Transmission Integrity Rules build upon existing regulations that codify modern integrity assessment technologies and processes. Integrity assessment programs are effective for managing an array of pipeline integrity threats and risk factors, as discussed in Section II above and in further detail below. Updating the class location change regulations to align with these newer technologies and rulemakings represents the opportunity for significant pipeline safety enhancements, because such an update would enable a substantial amount of resources to be allocated towards promoting the continued deployment of modern integrity assessment technologies and processes, as discussed in Section III above.

An integrity assessment option for managing class location changes will achieve the purpose of the class location change regulations – to ensure an appropriate safety margin when there is population growth around an existing pipeline. As long as it aligns with the 2016 Proposed Gas Transmission Integrity Rules, the integrity assessment option will be effective and appropriate for managing class changes, regardless of the specific reason for which a class change occurs. PHMSA need not establish different integrity assessment requirements based on whether the class change was due to the development of a new cluster or due to general population growth within the sliding mile. Class changes can also occur due to the construction of a single class 3 site.[31] The 2016 Proposed Gas Transmission Integrity Rules provide requirements for implementing modern integrity assessment technologies and processes that will effectively and efficiently ensure pipeline integrity regardless of why a class location change has occurred.

However, in regard to the clustering rule, the Associations strongly disagree with PHMSA's statement that "even a single house could form the basis of a second cluster..."[32] PHMSA should reconsider this statement in the next phase of this rulemaking. The idea that a single house can constitute a cluster is not consistent with the text, structure, or history of the regulations or longstanding industry practice. 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. Before establishing a new approach for applying the cluster rule, PHMSA should consider potential alternatives and obtain information from pipeline operators on the benefits and costs of those alternatives.

From their inception, class locations were intended as a crude mechanism for relating population density to risk exposure in the diverse areas traversed by pipelines. Prior to the codification of 49 C.F.R. 192, paragraph 841.015 of the 1968 edition of ASME B31.8 served as the interim pipeline safety standards for interstate pipelines. Class locations were defined as "the general description of a geographic area having certain characteristics as a basis for prescribing the types of construction and methods of testing to be used in those locations or in areas that are respectively comparable."[33] The descriptions for each class location were:

- *Class 1 locations include waste lands, deserts, rugged mountains, grazing land, and farm land, and combinations of these.*
- *Class 2 locations include areas where the degree of development is intermediate between Class 1 locations and Class 3 locations. Fringe areas around cities and towns, and farm or industrial areas.*
- *Class 3 locations include areas subdivided for residential or commercial purposes where, at the time of construction of the pipeline or piping system, 10 per cent or more of the lots abutting to the street or right-of-way in which the pipe is to be located are built upon, and a Class 4 classification is not called for. This permits classifying as Class 3, areas completely occupied by commercial or residential buildings with the prevalent height of three stories or less.*
- *Class 4 locations include areas where multistory buildings are prevalent and where traffic is heavy or dense and where there may be numerous other utilities underground.*[34] *Multistory means 4 or more "floors" above ground including the first or ground floor. The depth of basements or number of basement floors is immaterial.*[35]

[31] 49 C.F.R. § 192.5(b)(3)(ii).
[32] Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. 36,861, 36,863 (July 31, 2018).
[33] ASME, B31.8 Gas Transmission and Distribution Piping Systems Code ¶ 841.015 (1968).
[34] *Id.* ¶¶ 841.011 - .014.
[35] *Id.* at n.2

The codification of 49 Part C.F.R 192 in 1970 reduced the subjectivity associated with the class location definitions by providing threshold structure counts within the pipeline corridor to differentiate between class 1, 2 and 3 locations. However, since this was a change from the earlier "geography"-based definitions, the Agency was concerned that "…the proposed class location definitions could create a 2-mile stretch of high class location solely to protect a small cluster of buildings at a crossroad or road crossing."[36] Therefore, the Agency introduced the clustering concept to allow an operator to adjust the length of its class location boundaries in "thinly populated areas."[37] Whenever "a Class 2 or 3 location is required by a *cluster* of buildings in otherwise open country,"[38] the clustering rule allows an operator to end the class 2 or 3 location 220 yards from the nearest building in the cluster.[39] The Agency did not define "cluster" in the regulations.

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.[40] 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 *building<u>s</u>* 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."[41]

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 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 that prompted the higher-class designation. "Thinly populated areas" and "open country" – such as the grazing land and farm land referenced in the earlier definition for class 1 locations – often have more than zero buildings.[42] In 1970, during the discussions of the Committee on the proposed clustering rule, Mr. George White, Chief Engineer of the Tennessee Gas Pipeline Company, an member of the Committee, referred to a cluster as a "grouping within one mile."[43] 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

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[36] Establishment of Minimum Standards, 35 Fed. Reg. at 13,251.
[37] *Id.*
[38] *Id.* (emphasis added).
[39] 49 C.F.R. § 192.5(c)(1)-(2) (2017).
[40] *Thomas Jefferson Univ. v. Shalala*, 512 U.S. 504, 512 (1994) (citing *Gardebring v. Jenkins,* 485 U.S. 415, 430 (1988)).
[41] 49 C.F.R. § 192.5(c)(2)(emphasis added).
[42] Establishment of Minimum Standards, 35 Fed. Reg. at 13,251.
[43] Tr. of Technical Pipeline Safety Standards Committee, at 248:8-9 (June 24, 1970), https://www.regulations.gov/document?D=PHMSA-2014-0095-0034.

the Agency to explain what constituted a cluster.[44] 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."[45] The Merriam-Webster dictionary defines a cluster as "*a number of similar things that occur together.*"[46] The dictionary authors offered examples including "a group of buildings and especially houses built close together."[47] 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."[48] 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."[49] 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."[50]

PHMSA's view in the ANPRM that a cluster can include a single house conflicts with the rulemaking history and the recognized dictionary definition. A single house 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 house when viewed from this perspective is that it lacks each of these features. Accordingly, a single house cannot be part of 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.[51] 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.[52] The same flexibility should be offered to operators in applying "cluster."

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[44] Comments of the American Gas Association, Docket No. PS-124; Notice 1 (Sept. 30, 1992), https://www.regulations.gov/document?D=PHMSA-2015-0073-0007.

[45] 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).

[46] https://www.merriam-webster.com/dictionary/cluster (last accessed on Sept. 24, 2018)(emphasis added).

[47] *Id.*

[48] https://www.merriam-webster.com/dictionary/group (last accessed Sept. 24, 2018).

[49] PHMSA Letter of Interpretation, 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.").

[50] *In the Matter of El Paso Pipeline Corp. and ANR Pipeline Corp.* at 3, CPF No. 4-2007-1007 (Mar. 10, 2011) (emphasis added).

[51] PHMSA Letter of Interpretation, PI-07-0102 (Apr. 6, 2007).

[52] *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.").

Beyond the plain language of the regulation and the rulemaking history, the practical impacts of "a cluster of one" are completely inconsistent with the intent of class locations to be a mechanism for characterizing risk exposure based on population density. It is intuitive that the larger the cluster, the higher the level of risk exposure (due to higher population density). As such, when operators establish their clustering practices, they determine appropriate thresholds for cluster sizes to determine the appropriate classification of pipeline segments traversing them and establish the design and operational requirements to which they are subjected. PHMSA's ANPRM questions clearly recognize that clusters of fewer than 10 structures may represent a significantly lower risk exposure than the population densities normally associated with class 2, 3 and 4 areas.

During the next phase of this rulemaking, PHMSA should reconsider its statement that "even a single house could form the basis of a second cluster."[53] PHMSA should allow operators to continue to apply the ordinary meaning of the word and clarify that each operator has the obligation to determine the scope of a cluster as part of its class location program. That being said, if PHMSA intends to change its historical approach and adopt an interpretation of the clustering rule that is not based on the ordinary dictionary definition, the Agency should engage in a meaningful discussion of how a cluster should be defined, to better align class location designations with risk. This should be done through a rulemaking process and the Agency should consider the costs associated with potentially requiring operators to reevaluate their existing class location methodologies. The costs of such a change could constitute significant guidance and therefore trigger additional reviews.[54] 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. Finally, PHMSA cannot apply new regulations or guidance retroactively unless it has explicit statutory authority to do so.[55] The Pipeline Safety Act does not provide this type of authority. Therefore, any new definition of cluster cannot be applied retroactively to existing pipelines.

If PHMSA desires to generate more uniformity in how operators apply the clustering rule, the Agency should first look to develop a regulatory option for managing class location changes based on integrity assessments. PHMSA need not establish different integrity assessment requirements based on whether the class change was due to the development of a new cluster or due to general population growth within the sliding mile. As long as the integrity assessment method for managing class changes aligns with the 2016 Proposed Gas Transmission Integrity Rules, this method will be effective and appropriate for managing class changes, regardless of the specific reason for which a class change has occurred. An integrity assessment option will reduce the impact of the clustering concept on class changes by providing a practicable alternative to pipe replacements and pressure reductions for segments that have experienced two-class changes.[56] Since a change in the definition of "a cluster" may create new class location changes, an integrity assessment option for managing class changes may enable PHMSA to more easily promote alignment around the application of clustering and justify the associated costs.

[53] Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. at 36,863.
[54] Final Bulletin for Agency Good Guidance Practices, 72 Fed. Reg. 3,432 (Jan. 25, 2007); *See also,* Executive Order 12866, 58 Fed. Reg. 51,735 (Oct. 4, 1993), as amended.
[55] *Forsyth Mem'l Hosp., Inc., et al, v. Sebelius,* 652 F.3d 42, 43 (2011) (citing *Nat'l Mining Ass'n v. Dep't of Labor,* 292 F.3d. 849, 859 (D.C. Cir. 2002)).
[56] In general, operators cannot use the pressure test method to manage two (or more)-class changes (e.g., class 1 to class 3).

Q2a. – If so, what, if any, additional integrity management and maintenance approaches or safety measures should be applied to offset the impact on safety these proposals might create?

Q3a. – If so, what, if any, additional integrity management and maintenance approaches or safety measures should be applied to offset the impact on safety these proposals might create?

Q3b. – At what intervals and in what timeframes should operators be required to assess these pipelines and perform remediation measures?

Q4 – If PHMSA allows operators to perform certain IM measures in lieu of pipe replacement when class locations change from Class 1 to Class 3, should some sort of "fitness for service" standard determine which pipelines are eligible? Why or why not?

Several steps should be required when using integrity assessments to manage class location changes, in alignment with existing regulations and the 2016 Proposed Gas Transmission Integrity Rules. As an alternative to the current options in § 192.611, PHMSA should require an integrity assessment program that includes the following elements:

Maximum allowable operating pressure reconfirmation. If the segment involved in the class location change requires MAOP reconfirmation under proposed § 192.624(a), then PHMSA should require the operator to reconfirm the MAOP of the segment involved using one of the methods required in proposed § 192.624(c) **within 24 months** of identifying the change in class location. This timeline is consistent with the current timeline (§ 192.611(d)) for taking action following a class change.

By comparison, proposed § 192.624 would allow operators fifteen years to complete MAOP reconfirmation. This implementation timeline is appropriate when considering the entirety of the pipeline mileage covered by the pending MAOP reconfirmation requirement in the 2016 Proposed Gas Transmission Integrity Rules. However, operators can complete this requirement more quickly for the smaller amount of mileage involved in class changes annually. Requiring operators to complete MAOP reconfirmation (where required) more quickly for class change segments that are managed in accordance with the integrity assessment method will enhance pipeline safety.

Importantly, the maximum allowable operating pressure should be reconfirmed based on the pressure test factor required under § 192.619 or § 192.620, as applicable, *for the installed date and class location at the time of installation.* Otherwise, pipe replacement or pressure reduction might be required because a class change segment was not designed to accommodate the higher pressure test factors for class 3 & 4 areas. Requiring pipe replacement or pressure reduction to meet the class 3 & 4 pressure test factors would defeat the purpose of an integrity assessment method for managing class location changes.

Integrity assessments. The class location change requirements were intended for a specific purpose – to ensure an appropriate safety margin when there is population growth around an existing pipeline. Historically, pipe replacement, pressure reduction or pressure testing (where allowed for one-class changes) accomplished this objective. Installing thicker/stronger pipe or reducing pressure mitigates, to some extent, the effects of time-dependent and resident threats that could decrease a pipeline segment's margin of safety. This objective can now also be effectively accomplished using modern integrity assessment programs.

For the segment involved in the class location change, PHMSA should require the operator to identify each of the threats to which the segment is susceptible and conduct integrity assessments on the segment as follows:

- If the segment involved is not covered by subpart O, the operator must conduct initial integrity assessments for applicable threats in accordance with proposed § 192.710. **Initial assessments must be completed within 24 months** of identifying the change in class location (consistent with the current timeline at § 192.611(d))**.** Prior assessments may be used to meet this requirement in accordance with proposed § 192.710. Reassessments must be completed in accordance with proposed § 192.710, at intervals not to exceed 10 years. At a minimum, initial integrity assessments must include:
    - In-line inspection with a high resolution magnetic flux leakage tool, or an equivalent internal inspection device; and
    - Either a high resolution geometry or a high resolution deformation tool, or an equivalent internal inspection device.

  Additional tools or other assessment methods must be employed as needed to address all threats that the class change segment is susceptible to.

- If the segment involved is covered by subpart O, the operator must conduct initial integrity assessments for applicable threats in accordance with subpart O. **Initial assessments must be completed within 24 months** of identifying the change in class location (consistent with the current timeline at § 192.611(d))**.** Prior assessments may be used to meet this requirement in accordance with § 192.921. Reassessments must be completed in accordance with subpart O, at intervals not to exceed seven (7) years. At a minimum, initial integrity assessments must include:
    - In-line inspection with a high resolution magnetic flux leakage tool, or an equivalent internal inspection device; and
    - Either a high resolution geometry or a high resolution deformation tool, or an equivalent internal inspection device.

By comparison, proposed § 192.710, as modified by the Gas Pipeline Advisory Committee's (GPAC) recommendations, allows operators fourteen years to complete initial assessments, and existing § 192.921 allows operators 10 years to conduct initial assessments for newly identified covered segments. Although these implementation timelines are appropriate when considering the entirety of the pipeline mileage covered by existing regulations and the 2016 Proposed Gas Transmission Integrity Rules, operators can implement these programs more quickly for the smaller amount of mileage involved in class changes annually. Requiring operators to complete integrity assessments more quickly for class change segments will enhance pipeline safety.

As noted in Section II above, incentivizing the deployment of internal inspection technology has clear safety benefits. In the NTSB's 2015 safety study of integrity management programs, the NTSB made recommendations to PHMSA, AGA and INGAA to work to promote expanding the use of in-line inspection tools.[57] Adopting the Associations' recommendation for an integrity assessment method for managing class location changes will do just that.

Anomaly evaluation and remediation. As part of the 2016 Proposed Gas Transmission Integrity Rules, proposed § 192.710 would require operators to evaluate and remediate any discovered anomalies in accordance with the proposed § 192.713. Proposed revisions to §§ 192.921/192.937 would require operators to evaluate and remediate any discovered anomalies in accordance with the proposed revisions to § 192.933. The same anomaly evaluation and remediation requirements are appropriate for managing the integrity of class location change segments.

In accordance with proposed §§ 192.710(d)/192.921(a)(1), operators must explicitly consider uncertainties in reported integrity assessment results, including tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance in identifying and characterizing anomalies. This is an appropriate performance standard for ensuring that a reasonable degree of uncertainty is considered in integrity evaluations.

The MAOP reconfirmation, integrity assessment and anomaly response/repair requirements discussed above will demonstrate whether a pipeline is fit for service. Initial MAOP establishment, or MAOP reconfirmation where a pressure test record is not available, sets a physical safety margin that is then maintained for the life of the pipeline using integrity assessment, anomaly evaluation and repair/replacement, where required based on pipe condition.

As noted above, the Associations believe completing MAOP reconfirmation (where required) and initial integrity assessments will be practicable within 24 months for most class location changes. However, if an extension is needed due to unique circumstances, PHMSA should consider allowing operators to submit written notice with sufficient justification of the need for the extension.

In Section V below, the Associations have provided an example of regulatory language that could be added as § 192.611(a)(4) to reflect an integrity assessment method for managing class location changes.

[57] NTSB, Integrity Management of Gas Transmission Pipelines in High Consequence Areas (Jan. 27, 2015), https://dms.ntsb.gov/public/57000-57499/57122/569749.pdf. *See* NTSB, Safety Recommendations P-15-20, P-15-24 and P-15-26 (Feb. 10, 2015), https://www.ntsb.gov/safety/safety-recs/recletters/P-15-001-022.pdf, and https://www.ntsb.gov/safety/safety-recs/recletters/P-15-025-026.pdf.

B. <u>Grandfathered pipe should be addressed in accordance with the 2016 Proposed Gas Transmission Integrity Rules.</u>

> **Q1c. – Should part 192 continue to require pipe integrity upgrades for grandfathered pipe (e.g., pipe segments without a pressure test or with an inadequate pressure test, operating pressures above 72% SMYS, or inadequate or missing material records; see § 192.619(c))? Why or why not?**
>
> **Q4a. – If so, what factors should make a pipeline eligible or ineligible?**
>
> **(i) Should grandfathered pipe (lacking records, including pressure test or material records) or pipe operating above 72% SMYS be eligible? Why or why not?**

Grandfathered pipe should not be excluded from the integrity assessment option for managing class location changes, because the 2016 Proposed Gas Transmission Integrity Rules provide a process for reconfirming MAOP for grandfathered pipe segments. Any grandfathered pipe segment that has experienced a change from class 1 to class 3 or from class 2 to class 4 that operates at a hoop stress not commensurate with the new class location would be required to conduct MAOP reconfirmation under proposed § 192.624(a). As discussed above, if an operator decides to use the proposed integrity assessment method to manage a class change on a segment that requires MAOP reconfirmation under proposed § 192.624(a), PHMSA should require the operator to reconfirm the MAOP of the class change segment using one of the methods required in §192.624(c) **<u>within 24 months</u>** of identifying the change in class location. Importantly, the maximum allowable operating pressure should be reconfirmed based on the test factor *for the installed date and class location at the time of installation.*

The Associations recommend the following hoop stress limitations for class location change segments managed using the integrity assessment method:

- 80 percent of the SMYS in Class 2 locations;
- 72 percent of SMYS in Class 3 locations; or,
- 60 percent of SMYS in Class 4 locations.

Certain pipelines in class 1 areas are permitted to operate above 72 percent of SMYS, in accordance with § 192.619(c) or § 192.620. Therefore, it is safe and appropriate for PHMSA to allow operators to use an integrity assessment method to manage class 1 to class 2 changes up to 80 percent of SMYS. This is consistent with several existing special permits. In Section V below, the Associations have provided an example of regulatory language that would accommodate this.

C. Categorical exclusions based on a specific pipe attributes are unwarranted. The integrity assessment option should require operators to evaluate relevant threats, conduct integrity assessments and perform remedial measures.

4a.

(ii) **Should pipe that has experienced an in-service failure, was manufactured with a material or seam welding process during a time or by a manufacturer where there are now known integrity issues or has lower toughness in the pipe and weld seam (Charpy impact value) be eligible? Should pipe with a failure or leak history be eligible? Why or why not?**

(iii) **Should pipe that contains or is susceptible to cracking, including in the body, seam, or girth weld, or having disbonded coating or CP shielding coatings be eligible? Are there coating types that should disqualify pipe? Should some types of pipe, such as lap-welded, flash-welded, or low-frequency electric resistance welded pipe be ineligible? Should pipe where the seam type is unknown be ineligible? Why or why not?**

(vii) **Should pipe lacking cathodic protection due to disbonded coating be eligible? Why or why not?**

(viii) **Should pipe with properties such as low frequency electric resistance weld (LF-ERW), lap welded, or other seam types that have a history of seam failure due to poor manufacturing properties or seam types that have a derating factor below 1.0 be eligible? Why or why not?**

Categorical exclusions based on a specific pipe attribute considered in isolation are unwarranted. Pipeline segments should not be broadly excluded from the proposed integrity assessment method for managing class location changes simply based on potential threats. Instead, the integrity assessment alternative for managing class location changes should direct operators to existing regulations or the 2016 Proposed Gas Transmission Integrity Rules (as endorsed by the GPAC), as appropriate, for managing specific threats.

PHMSA should encourage the use of modern integrity assessment technologies. Through performing threat evaluation, integrity assessments, and remedial measures, operators have the ability to address any threats to the integrity of a pipeline and, in the process, learn valuable information about their pipeline system. Rather than imposing unnecessary barriers to utilizing the integrity assessment method for managing class location changes, PHMSA should use the process as an incentive to focus operator resources on addressing the actual threats to their pipelines. Reducing pressure, replacing a short pipe segment and even pressure testing does not necessarily address or eliminate all threats, and provides little information to benefit overall system integrity.

Below are examples of how operators address some of the specific threats mentioned in Question 4a using integrity assessment programs. The examples provided are not exhaustive.

Managing segments susceptible to the cracking threat

The integrity assessment requirements in proposed § 192.710 for non-HCAs and existing §§ 192.921/192.937 for HCAs require operators to conduct assessments capable of identifying anomalies and defects associated with *each of the threats to which the pipeline segment is susceptible*. To determine what assessments are required to address potential cracking threats, operators consider construction and maintenance histories, coating and material properties and environmental characteristics for the segment and compare these to similar pipe that has experienced cracking issues. Based on these and other factors, if an operator identifies that a segment is susceptible to the cracking threat, the operator then establishes a schedule for conducting integrity assessments in accordance with proposed § 192.710 or §§ 192.921/192.937, as applicable. Based on the results of these assessments, operators conduct any necessary anomaly evaluation and remediation in accordance with proposed § 192.713 or existing § 192.933.

For example, in considering whether there is a cracking threat to the girth welds on a pipeline segment, operators may consider whether there has been a history of in-service leaks or breaks in the girth welds, the terrain along the segment and any nondestructive testing that has been conducted on the girth weld. This type of threat evaluation is inherent as part of the integrity assessment requirement under proposed § 192.710 and existing §§ 192.921/192.937, although the specific considerations and evaluation will vary based on the unique attributes of the pipe segment. Therefore, prescriptive requirements for threat evaluation beyond what is included under proposed § 192.710 and existing §§ 192.921/192.937 are not necessary or appropriate.

As another example, if an operator identifies, through threat evaluation, that the class location change segment is susceptible to stress corrosion cracking (SCC), then proposed § 192.710 and proposed revised §§ 192.921/192.937 require assessment for SCC using spike pressure testing (proposed § 192.506), inline inspection (proposed § 192.493) or SCC DA (§ 192.929).

If an operator's threat evaluation determines that an integrity assessment for cracking is appropriate, and if any cracking is identified by the assessment, PHMSA has proposed rigorous new anomaly response and repair requirements as part of the 2016 Proposed Gas Transmission Integrity Rules. This includes an entire new fracture mechanics modeling process, proposed §192.712, for evaluating potential crack anomalies and responding accordingly. PHMSA and the GPAC discussed appropriate requirements for responding to cracking anomalies during the March 26-28, 2018 GPAC meeting. These new requirements will ensure acceptable pipe condition and an adequate safety margin, regardless of whether a class change has occurred. For all pipelines operating above 40% of SMYS (which includes all pipelines subject to the class location change regulations in § 192.611), the Associations expect that the new anomaly response requirements for cracking will include:[58]

Immediate Response Requirement (all classes):

- Crack depth greater than 50% of pipe wall thickness, as measured at the crack location; or

[58] GPAC Meeting Final Voting Slides at 21-22 (Mar. 26-28, 2018), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=966.

- Fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to MAOP x 1.1 or 1.25.[59]

Scheduled Response Requirement:

- Class 1: Fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to MAOP x 1.39, unless the failure stress pressure is greater than or equal to the MAOP times the reciprocal of the design factor of the installed pipe.

- Class 2, 3 and 4: Fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to MAOP x 1.50, unless the failure stress pressure is greater than or equal to the MAOP times the reciprocal of the design factor of the installed pipe.[60]

Monitored Condition Requirement:

- Fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly that is:
  - Greater than MAOP x 1.39 for class 1 locations and MAOP x 1.50 for class 2, 3 and 4 locations times the MAOP; or
  - Greater than or equal to the MAOP times the reciprocal of the design factor of the installed pipe.

In the existing Integrity Management Program regulations and 2016 Proposed Gas Transmission Integrity Rules, there are no automatic requirements for pipe replacement or pressure reductions for segments that might be susceptible to the cracking threat. This is because these pipelines can be effectively managed using integrity assessments programs.

Managing potential CP shielding

Similarly, pipelines can be safely managed when there is a potential cathodic protection (CP) shielding issue (disbonded coating, shielding coating, etc.). Integrity assessments for corrosion threats, which are required under proposed § 192.710 and §§ 192.921/192.937, can identify areas of corrosion that may be caused by coating shielding issues. These areas are then specifically targeted for mitigation or remediation (*in situ* examination, recoating, pipe replacement, more frequent assessments, etc.).

When a class location change occurs, existing requirements to replace pipe or reduce pressure are not an effective way to manage CP shielding issues on the pipeline. Replacing the pipe might resolve the shielding issue for that particular segment, but this does not resolve CP shielding issues for the remainder of the pipeline segment, nor does the operator gains information about threats that could be affecting the rest of the system. Furthermore, reducing pressure or performing a pressure test would not resolve the shielding or prevent corrosion. If corrosion is occurring, a pressure reduction might delay the failure,

[59] The GPAC directed PHMSA to "consider 1.1 x MAOP for immediate conditions after tool tolerance has been field verified and applied." *Id.* at 22.
[60] Conditions on segments that have experienced a class location change will be evaluated using the criteria for the new class location (class 2, class 3 or class 4).

but it will not prevent it. A pressure test (where allowed for one-class change) would identify the corrosion anomaly, but only if it had progressed significantly.

Using an integrity assessment approach would identify any corrosion that could have been caused by shielding before the anomaly grows to failure and also provide data that is useful for managing overall pipeline system integrity. Integrity assessments provide significantly more information about the system than replacing short pipe segments. Thus, managing CP shielding using the integrity assessment method may offer superior pipeline safety benefits relative to the other methods currently allowed for managing class location changes.

In the existing Integrity Management Program regulations and 2016 Proposed Gas Transmission Integrity Rules, there are no automatic requirements for pipe replacement, pressure reduction or pressure testing for segments with shielding coatings. This is because these pipelines can be effectively managed using integrity assessments programs.

The 2016 Proposed Gas Transmission Integrity Rules also require that each operator whose pipeline system is subjected to stray currents have in effect a continuing program to minimize the detrimental effects of such currents, including the interference current management program required by proposed § 192.473(c). The pending rules require interference surveys to be taken on periodic basis including when there are current flow increases over pipeline segment. Operators must analyze results of the survey to determine the cause of the interference and whether the level could cause significant corrosion, or if it impedes the safe operation of a pipeline. The operator must complete all remediation within 12 months or as soon as practicable after obtaining necessary permits.

Managing shorted casings

Similarly, an exclusion related to shorted casings is not necessary or appropriate. Shorted casings are effectively managed through existing § 192.467(c) and the integrity assessment programs in proposed § 192.710 and §§ 192.921/192.937. The Associations are recommending that initial integrity assessments for class location change segments include a high-resolution MFL tool inspection (or equivalent internal inspection). That assessment will allow operators to effectively identify any shorted casings where corrosion is actually occurring, and to remediate those segments in accordance with proposed § 192.713 or existing § 192.933, as applicable.

High-resolution MFL ILI data from the Associations shows that the majority of the shorted casings are clean with no or inactive (low growth) corrosion. One study has analyzed ILI data for an estimated 51,500 casings.[61] This analysis determined that 17% of the estimated total number of casings in the US were either metallically or electrolytically shorted. However, only 2% had corrosion. Based on these statistics, it is clear that corrosion is <u>not occurring</u> within the majority of the shorted casings.

The results of that study are consistent with other findings. For example, a large interstate natural gas transmission operator has recently conducted a detailed study of pipeline integrity data and historical performance of pipelines within casings to better understand how to ensure safety. A review of historical incident data found that once a high-resolution MFL inspection program was implemented, failures within casings no longer occurred, both for shorted and non-shorted casings.

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[61] Goran Camitz, *Cathodic Protection of Natural Gas Pipelines with Casings at Road and Railway Crossings – International Practice and Experience*, Paper No. 45, NACE International Corrosion Conference (1984).

Clearing all shorted casings where the majority of them do not have significant corrosion does not address the locations that are most likely to fail. High-resolution ILI technology and an assessment-based corrosion management program are able to provide an effective holistic approach to manage the threat of corrosion on pipelines within casings (shorted and non-shorted). High-resolution ILI assessments and the associated excavation programs generate a wealth of valuable data which can be used to manage the corrosion threat more effectively. The performance of high resolution MFL inspections within casings is understood and the change in magnetization has been accounted for sizing algorithms. With consecutive assessment runs at appropriate inspection intervals, any significant growth of corrosion anomalies in a shorted casing can be accurately identified, monitored and accessed for visual evaluation. The sizing capabilities of ILI tools can be validated using post-ILI excavation data. The operator study of shorted casings referenced above demonstrated that the most extreme growth rates on shorted casings were identified by the ILI program, leading to timely mitigation.

While some casing shorts may be easily cleared, many others are impractical to clear. Casings are often used in areas that are difficult to access (e.g. under major roads and highways). In many cases, the requirement for current class change special permits to clear all the shorted casings (regardless whether they are corroded or not) is impracticable and does not necessarily provide any safety or integrity benefits. When the attempt to clear a casing short is unsuccessful, excavation or pipe replacement with re-route becomes one of the few options to permanently and confidently remove the casing short. Again, since casings are often in areas that are difficult to access, these options are costly, disruptive and do not improve pipeline safety if integrity assessment has demonstrated that the pipe is in in safe, operable condition. Unnecessary construction activities also divert resources away from performing higher value work at locations with higher risk.

For these reasons, PHMSA should not exclude shorted casings from its integrity assessment option for managing class location changes. To prevent failures on shorted casings, non-shorted casings and uncased pipe, operators can use integrity assessments to focus work on locations with the highest risk and highest probability of failure. Based on extensive study of corrosion and historical performance within casings, it is clear that using high-resolution MFL ILI technology as part of an integrity assessment-based corrosion management program provides an effective approach to address the threat of corrosion.

Incorporating previous failure/leak history into integrity assessment programs

A previous failure or leak does not automatically mean that a pipeline segment is unsafe and must be replaced or retested. Failure and leak history is important information that must be considered in establishing assessment methods and frequencies in accordance with proposed § 192.710 and §§ 192.921/192.937. However, an in-service failure should not automatically disqualify a class location change segment from the integrity assessment method.

PHMSA initially proposed language related to in-service failures in the scope of its MAOP reconfirmation regulation (§ 192.624(a)). During the December 11-12, 2017 GPAC meetings, the committee discussed that this type of information should be incorporated into an operator's pipeline integrity program and used to determine appropriate assessment methods and frequencies. At the March

26-28, 2018 GPAC meeting, PHMSA proposed moving this language from the MAOP reconfirmation section to the Integrity Management Program requirements in subpart O.[62]

Managing vintage manufacturing and construction threats

Manufacturing and construction threats must be considered in establishing assessment methods and frequencies in accordance with proposed § 192.710 and §§ 192.921/192.937.

For example, many pipe segments with low frequency ERW pipe are safely managed in all class locations today – moving from one class to another does not inherently decrease safety, if an operator is evaluating the seam threat and performing appropriate recurring integrity assessments.

If a pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe, or pipe with seam factor less than 1.0 as defined in § 192.113, operators will first evaluate the pipe to determine if it is susceptible to the threat of seam failure, consistent with the requirements under proposed § 192.710 and proposed revised §§ 192.921/192.937. Established processes for evaluating seam threats consider construction and maintenance histories, coating and material properties and environmental characteristics and compare these to similar pipe that has experienced seam failure. If the seam is determined to be a threat to the pipeline, operators select an assessment technology or technologies with a proven application capable of assessing seam integrity and establish a schedule for conducting integrity assessments in accordance with proposed § 192.710 or §§ 192.921/192.937. Any conditions discovered during the integrity assessments will be evaluated and remediated in accordance with proposed § 192.713 or § 192.933, as necessary.

Similarly, wrinkle bends can be managed safely, regardless of class location. Wrinkle bends resulted from common practices used in the past to bend pipe in the field. Thousands of wrinkle bends were introduced during that time, and the vast majority have operated safely since then. While a few wrinkle bends have failed in service, the failure frequency of wrinkle bends is extremely small, with only about 1 in 8,000 wrinkle bends failing over approximately seventy years of service.[63] The vast majority of these failures occurred prior to the development of modern pipeline integrity practices. Furthermore, most of these incidents are leaks, as opposed to ruptures, as wrinkle bends tend to fail as a guillotine fracture of part of the pipe circumference.

As with other vintage manufacturing and construction threats, wrinkle bends can be effectively managed through sound engineering practices and leveraging advances in integrity assessment technology, where appropriate. Where an operator identifies wrinkle bends as a threat to pipe integrity, proposed § 192.710 and existing § 192.921/192.937require the operator to implement integrity assessment practices to identify and evaluate wrinkle bends that have hazardous defects. Furthermore,

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[62] PHMSA, GPAC-Slide_Presentation_-Gas_Rule_-_March_26_to_28_Mtg_5_-_FINAL, at 11 (Mar. 26-28, 2018), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=942. ("PHMSA: suggests striking 192.624(a)(1) based upon Committee recommendation. Instead, PHMSA suggests including a new 192.917(e)(6) to address failures due to cracks and crack-like defects in HCAs within the integrity management program, as recommended by committee members.").

[63] 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)" (Dec. 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.

the use of sound engineering and integrity assessment practices, in lieu of pipe replacement, can avoid disturbing existing wrinkle bends intended for continued service, as wrinkle bend failures are historically associated with outside forces. Integrity assessments on a class location change segment may also provide useful information for managing the integrity of the entire pipeline system – replacing a class change segment simply because it contains wrinkle bends provides no such value.

PHMSA's current class change regulations also allow for pressure reduction instead of pipe replacement where a class location change has occurred. However, as previously noted, delivery obligations often make a long-term pressure reduction infeasible. Furthermore, a pressure reduction may do little to prevent a wrinkle bend failure. In the rare instances where wrinkle bend failures have occurred, generally pipe hoop stress did not contribute to the failure mechanism.

In the existing Integrity Management Program regulations and 2016 Proposed Gas Transmission Integrity Rules, there are no automatic requirements for pipe replacement or pressure reductions for segments with vintage manufacturing and construction features. This is because these pipelines can be effectively managed using prudent integrity assessments programs.

D. <u>Anomalies discovered through integrity assessment should be addressed in accordance with the 2016 Proposed Gas Transmission Integrity Rules.</u>

4a.

(iv) Should pipe with significant corrosion (wall loss) be eligible for certain IM measures, or should it be replaced? Why or why not?

PHMSA has proposed rigorous new anomaly evaluation and remediation requirements as part of the 2016 Proposed Gas Transmission Integrity Rules. PHMSA and the GPAC discussed appropriate requirements for responding to wall loss anomalies during the March 26-28, 2018 GPAC meeting. These new requirements will ensure safety, regardless of whether a class change has occurred.

When integrity assessments on class location change segments identify anomalies, including wall loss, the 2016 Proposed Gas Transmission Integrity Rules for pipelines outside of HCAs and the existing regulations for pipelines in HCAs require operators to evaluate and remediate anomalies in accordance with proposed § 192.713 and § 192.933. In fact, because an integrity assessment method for managing class location changes will inevitably lead to expedited assessments inside and outside of class change segments (i.e., **<u>within 24 months</u>** of identifying the change in class location), adding this integrity assessment alternative will certainly result in more pipe anomalies being identified and addressed at a quicker pace. Each year, an integrity assessment method for managing class location changes will likely require operators to assess thousands of additional miles of pipe and address any anomalies discovered – instead of replacing a small amount of already-safe mileage.

If an anomaly (after *in situ* verification) meets the immediate or scheduled response requirement, it will be remediated, or the pipe will be replaced. For all pipelines operating above 40% of SMYS, the new wall loss anomaly response requirements will be:[64]

Immediate Response Requirement: MAOP x 1.1 (all classes)

Scheduled Response Requirement:

- Class 1: Respond per ASME B31.8S (2004) Section 7, Figure 4
- Class 2: Respond per ASME B31.8S (2004) Section 7, Figure 4[65]
- Class 3: MAOP x 1.39 or 1.5, or MAOP x reciprocal of design factor of the installed pipe
- Class 4: MAOP x 1.39 or 1.5, or MAOP x reciprocal of design factor of the installed pipe

[64] GPAC Meeting Final Voting Slides. March 26-28, 2018. Slide 25.

[65] Conditions on segments that have experienced a class location change will be evaluated using the criteria for the new class location (class 2, class 3 or class 4).

4a.

(v) Should anomalies be repaired similar to IM, allowed to grow to only a 10-percent safety factor (§ 192.933(d)) before remediation in high population areas such as Class 2, 3 and 4 locations, or should they have an increased safety factor for remediation should these class location factors be eliminated? Why or why not?

As noted previously, PHMSA and the GPAC discussed appropriate requirements for responding to wall loss anomalies during the March 26-28, 2018 GPAC meeting. The GPAC discussed PHMSA's concern that current ASME B31.8S and subpart O requirements allow anomalies to grow to 1.1 x MAOP. PHMSA's assertion that operators are allowing anomalies to grow to a dangerous level was presented with no supporting data or analyses to demonstrate that this practice is prevalent or creating a public safety threat. PHMSA provided zero examples of incidents that had been caused by an operator allowing a wall loss anomaly to grow to 1.1 x MAOP. Still, to address PHMSA's concern, the GPAC endorsed more rigorous requirements for anomaly response and repair in class 3 and 4 areas, which also provide an appropriate threshold for anomaly response on pipe segments that have experienced a class change to class 3 or class 4.

In reviewing internal/external corrosion incidents reported to PHMSA since 2010, the Associations identified that more than 70% of these incidents occurred on segments <u>that had NOT been assessed for metal loss anomalies with ILI</u>. The ASME B31.8S (2004) Section 7, Figure 4 requirements apply primarily to lines that have had internal inspection. The fact that most corrosion incidents have occurred on pipelines that have not been inspected with an internal inspection tool indicates that following the current industry practice to remediate corrosion anomalies based on ASME B31.8S (2004) Section 7, Figure 4 is an effective practice. Even more importantly, this demonstrates that integrity assessment practices are often more relevant than pipe stress in preventing an incident, and that an integrity assessment method for managing class changes in lieu of pipe replacements, pressure reductions or pressure testing represents a significant opportunity to enhance pipeline safety.

4a.

(vi) Should pipe that has been damaged (dented) or has lost ground cover due to 3rd party activity (excavation or other) be eligible? Why or why not?

Managing dent anomalies through integrity assessments

PHMSA has proposed rigorous new anomaly response and repair requirements as part of the 2016 Proposed Gas Transmission Integrity Rules. PHMSA and the GPAC discussed appropriate requirements for responding to dent anomalies during the March 26-28, 2018 GPAC meeting. These new requirements will ensure safety, regardless of whether a class change has occurred. Operators will be required to evaluate, respond to and repair/replace, as required, pipe with dent anomalies in accordance with PHMSA's 2016 Proposed Gas Transmission Integrity Rules at proposed § 192.713 (outside of HCAs) and proposed revised § 192.933 (within HCAs). PHMSA's proposed new dent anomaly response requirements are identical for all class locations.

In fact, because an integrity assessment method for managing class location changes will inevitably lead to expedited assessments inside and outside of class change areas (i.e., **within 24 months** of identifying the change in class location), adding this integrity assessment method certainly will result in more pipe anomalies being identified and addressed than otherwise would be. Each year, an integrity assessment method for managing class location changes will likely require operators to assess thousands of additional miles of pipe and address any anomalies discovered – instead of replacing a small amount of already-safe mileage.

The new dent anomaly response requirements for pipelines operating above 40% of SMYS will be:[66]

Immediate Response Requirement (all classes):

- 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 an engineering critical assessment of the dent demonstrates that critical strain levels are not exceeded.

Scheduled Response Requirement (all classes):

- 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% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses of the dent demonstrate critical strain levels are not exceeded.
- A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a detected longitudinal or helical (spiral) seam weld, unless engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded.
- A dent located between the 4 o'clock position and the 8 o'clock position (bottom 1⁄3 of the pipe) that has metal loss, cracking or a stress riser, unless an engineering critical assessment of the dent demonstrates that critical strain levels are not exceeded.

Monitored Condition Requirement (all classes):

- A dent with a depth greater than 6% 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).
- 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% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.
- A dent with a depth greater than 2% of the pipeline’s diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a detected longitudinal or helical (spiral) seam weld, and engineering analyses of the

[66] GPAC Meeting Final Voting Slides at 20 (Mar. 26-28, 2018).

dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

- A dent that has metal loss, cracking or a stress riser and engineering critical assessment of the dent demonstrates that critical strain levels are not exceeded.

Managing loss of cover

To monitor for loss of cover and potential impacts on pipeline safety, operators are already required in § 192.705 to conduct patrols with increasing frequency in class 3 and 4 areas, per **Table 1** below. Furthermore, the 2016 Proposed Gas Transmission Integrity Rules will require operators to implement additional inspections following extreme weather events (proposed § 192.613(c)), which is the most likely cause of a sudden change in depth of cover. These existing and pending requirements are sufficient to monitor depth of cover changes to ensure pipeline safety, regardless of whether a class change has occurred.

Maximum interval between patrols		
Class location of line	**At highway and railroad crossings**	**At all other places**
1, 2	7½ months; but at least twice each calendar year	15 months; but at least once each calendar year.
3	4½ months; but at least four times each calendar year	7½ months; but at least twice each calendar year.
4	4½ months; but at least four times each calendar year	4½ months; but at least four times each calendar

Table 1: *Patrol Requirements in § 192.705*

E. PHMSA should align the integrity assessment option with the 2016 Proposed Gas Transmission Integrity Rules, instead of incorporating class location change waiver guidance or special permit conditions into regulations.

4b. – Should PHMSA base any proposed requirements off its criteria used for considering class location change waivers (69 FR 38948; June 29, 2004), including the age and manufacturing and construction processes of the pipe, and O&M history? Why or why not?

Q6 – Should PHMSA incorporate its special permit conditions regarding class location changes into the regulations, and would this incorporation satisfy the need for alternative approaches? Why or why not? (Examples of typical PHMSA class location special permit conditions can be found at https://primis.phmsa.dot.gov/classloc/documents.htm.)

6a. – What, if any, special permit conditions could be incorporated into the regulations to provide regulatory certainty and public safety in these high population density areas (Class 2, 3, and 4)?

As outlined in these comments, many of the current class location change special permit requirements will be applied throughout the gas transmission pipeline network as part of PHMSA's 2016 Proposed Gas Transmission Integrity Rules. The Associations strongly support these pending gas transmission integrity regulations, as endorsed by the GPAC. PHMSA should require operators to implement the new integrity assessment requirements within twenty-four (24) months of identifying the class location change, as an alternative to existing options for managing class change segments. Conducting integrity assessments for all threats that are applicable to a particular pipe segment and repairing or replacing pipe as required based on its condition will achieve the purpose of the class location change regulations – to ensure an appropriate safety margin when there is population growth around an existing pipeline. Updating the class location change regulations to align with these newer rulemakings will enable a substantial amount of resources to be reallocated to promote the continued deployment of modern integrity assessment technologies and represents a significant step forward in the pursuit of perfect safety performance

However, not every class change special permit requirement is necessary to ensure pipeline safety, or appropriate for inclusion in the proposed integrity assessment method for managing class location changes. Class location change special permits have functioned as a pilot program for deploying integrity management principles. PHMSA is now incorporating the integrity practices that have shown to be most effective into the 2016 Proposed Gas Transmission Integrity Rules.

Additional requirements beyond the 2016 Proposed Gas Transmission Integrity Rules are not needed to ensure the safety of segments that have experienced a class location change. The GPAC discussions associated with the 2016 Proposed Gas Transmission Integrity Rules reflect the best current thinking on many important pipeline safety topics, reflecting input from a broad group of federal and state government, public and industry stakeholders. The special permit conditions were not designed for broad application as regulatory text. If PHMSA proceeds to develop new class location integrity management requirements "from scratch" or using the special permit template, the deployment of modern integrity assessment technologies will likely be hindered while operators wait years for PHMSA to complete yet another protracted rulemaking. PHMSA should provide an integrity assessment method for managing class location changes that aligns with the pending and existing integrity regulations.

The following typical conditions[67] from class location change special permits were discussed as part of the 2016 Proposed Gas Transmission Integrity Rules:

- Maximum allowable operating pressure (MAOP)
- Close interval surveys
- ACVG or DCVG (**note: following GPAC discussion, a periodic ACVG or DCVG requirement was <u>not</u> recommended for inclusion in final rules**)
- Stress corrosion cracking direct assessment
- In-line inspection initial assessment
- Cathodic protection test station – remediation
- Interference current control
- Anomaly evaluation and repair
- Pipe seam evaluations
- Data integration
- Pipe properties records

After considering technical feasibility, reasonableness, cost-effectiveness and practicability, the GPAC recommended modification or removal of certain special permit conditions that were originally included in the 2016 Proposed Gas Transmission Integrity Rules. For example, recurring voltage gradient survey requirements were removed from PHMSA's final GPAC proposal,[68] and the proposed anomaly response and remediation requirements were substantially revised.[69] This indicates that not every current class change special permit requirement is necessary to ensure pipeline safety or appropriate for inclusion in the integrity assessment method for managing class location changes.

As acknowledged in the ANPRM, PHMSA has not revisited the class location special permit conditions that were initially developed in 2004.[70] Almost fifteen years of engineering and technological advancement has occurred since then, yet PHMSA continues to use conditions first established in 2004. Therefore, PHMSA should not assume that each condition in current class change special permits should be included in the proposed integrity assessment method for managing class location changes.

Nor should PHMSA presume that just because an individual operator agrees to a specific requirement in a special permit, the operator agrees that the requirement is reasonable and value-adding. Operators

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[67] PHMSA, *Example Class Location Special Permit Typical Conditions*.
[68] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. at 20,847, proposed 49 C.F.R. § 192.935(g)(2)(i) (endorsed for removal by the GPAC).
[69] GPAC Meeting Final Voting Slides at 17-25 (Mar. 26-28, 2018).
[70] Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. at 36,864.

are often faced with the choice to either agree to PHMSA's proposed special permit conditions or unnecessarily replace pipe due to a class location change. In these situations, operators are inclined to acquiesce to unnecessary special permit conditions for a specific class change segment, even if these conditions would be unacceptable if applied more broadly.

ACVG/DCVG surveys

ACVG and DCVG surveys should not be required for every class change segment managed in accordance with the integrity assessment method. If operators ensure adequate CP, corrosion will not occur. Consistent with proposed revisions to § 192.465, where any annual test reading indicates inadequate CP levels, operators will conduct close interval surveys (CIS) in both directions from the test station with a low CP reading. Operators will remediate any areas of inadequate CP within 12 months or as soon as practicable after obtaining necessary permits. Additionally, integrity assessments required for corrosion threats under proposed § 192.710 (outside of HCAs) and existing §§ 192.921/192.937 (within HCAs) can identify areas of corrosion that may be caused by coating issues. So, the 2016 Proposed Gas Transmission Integrity Rules will require at least two layers of protection to ensure corrosion control systems are adequately functioning.

ACVG or DCVG assessments are neither necessary nor sufficient to determine if a pipeline is effectively protected against external corrosion. ACVG or DCVG only provide a relative assessment of coating effectiveness. For example, performing ACVG or DCVG on a bare pipeline (e.g. pre-1971) would produce no actionable coating indications, regardless of the level of CP. However, performing CP surveys in accordance with proposed revised § 192.465 and performing integrity assessments in accordance with proposed § 192.710 or existing §§ 192.921/192.937 would each identify potential and actual corrosion control issues, regardless of the vintage or quality of the coating system.

If an operator confirms adequate CP through annual surveys, identifies specific areas of low CP using CIS and addresses these areas in accordance with the proposed revisions to § 192.465, and conducts periodic corrosion assessments in accordance with § 192.710 or §§ 192.921/192.937, then the segment is adequately protected from a failure due to corrosion. A periodic ACVG/DCVG assessment requirement for HCAs was discussed at PHMSA's June 2017 GPAC meeting (originally proposed § 192.935(g)(2)(i)). Commenters noted the unique burden associated with conducting ACVG/DCVG on operating pipelines and the low safety value of this requirement for pipelines that have adequate CP surveying and integrity assessments for corrosion threats.[71] In addition, ACVG or DCVG assessments are not effective for coatings that electrically shield. Ultimately, PHMSA withdrew the periodic ACVG/DCVG assessment requirement from its final corrosion control proposal that was endorsed by the GPAC.

As noted by Member Zamarin during the GPAC discussions, "[S]aying that an inline inspection or a CIS survey does not assess the adequacy of a coating system is just flat-out wrong. If you have inline inspection that's demonstrating that there is no corrosion, you by default have adequate protection."[72]

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[71] *See* Tr. of Technical Pipeline Safety Standards Committee at 44:21 – 47:6 (June 6, 2017) (Drew Hevle, Kinder Morgan), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=874.

[72] *Id.* at 51:20 – 52:4 (comments of Mr. Chad J. Zamarin, President, Cheniere Pipeline Co.). Furthermore, "And if we spend all of our resources looking for the very small . . . imperfection in the coating system when we have a secondary cathodic protection system, and we have an inline inspection system, and we have other systems

Treating all class change segments as HCAs

Current class change special permits require operators to treat all class change segments as HCAs. Now that PHMSA is expanding integrity management outside of HCAs through its 2016 Proposed Gas Transmission Integrity Rules, treating every class change segment equally as an HCA is neither necessary nor appropriate. A class location change segment should be managed in accordance with the applicable regulations for the class location and consequence area designation that applies to the segment after the class change has occurred. If a segment that has experienced a two-class change does not meet the codified definition of an HCA, it would be managed in accordance with the 2016 Proposed Gas Transmission Integrity Rules that will apply to all class 3/4 areas and certain MCAs.

As noted previously, the new requirements that will apply outside of HCAs have been endorsed by the GPAC for those types of locations/areas. These requirements for class 3/4 non-HCAs and MCAs were heavily influenced by the existing requirements within HCAs and requirements in current class location change special permits.

4c. – In the 2004 Federal Register notice (69 FR 38948), PHMSA outlines certain requirements pipelines must meet to be eligible for waiver consideration, including no bare pipe or pipe with wrinkle bends, records of a hydrostatic test to at least 1.25 times MAOP, records of ILI runs with no significant anomalies that would indicate systemic problems, and agreement that up to 25 miles of pipe both upstream and downstream of the waiver location must be included in the operator's IM program and periodically inspected using ILI technology. Further, the criteria provides no waivers for segments changing to Class 4 locations or for pipe changing to a Class 3 location that is operating above 72% SMYS. Should PHMSA require operators and pipelines to meet the threshold conditions outlined earlier in this document (Section 3A; "Class Location Change Special Permits – Special Permit Conditions) or other thresholds to be eligible for a waiver when class locations change? Why or why not?

Inspection areas upstream and downstream of class change

An integrity assessment method for managing class location changes will certainly result in inspection of a substantial amount of pipeline mileage outside of the class change segment. Regardless of assessment method, it is rarely possible to inspect just a specific segment that has experienced a class change. For example, ILI launchers and receivers are often placed approximately 30 – 60 miles or more apart on transmission pipelines, so a 1,000-foot class change at the midway point between a launcher and receiver might necessitate the inspection of 39-59 miles of extra pipeline that has not experienced a class change. Most class location changes are less than mile in length.

However, it is unnecessary and inappropriate to prescribe a *specific* inspection length upstream and downstream of each class change segment. Anomalies on pipe that is miles upstream or downstream of

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designed . . . that are less intrusive, that don't require excavations and exposure of workers to safety issues, we start to get down a very slippery slope. . . . I think perfect coating is a great concept, but it's something that in attempting to achieve may result in other issues that are unforeseen, and there may be better ways to address that particular issue." *Id*. at 65:8-21.

a class change segment have no bearing on the integrity of the class change segment. There is no class location change-related reason to require extra inspections on segments that are not involved in a class change. Covering 50 miles with any assessment method can often require multiple assessment runs. Requiring multiple assessments in different locations to demonstrate the integrity of a short class change segment is neither reasonable nor appropriate. This burden is amplified by the extensive reporting requirements that PHMSA has applied to inspection areas in existing special permits. Pipe upstream and downstream of a class change area will still be managed safely, in accordance with existing and pending regulations that are applicable to the broader pipeline system, including requirements for operations and maintenance, corrosion control, integrity assessments, anomaly evaluation and remediation and other activities. For example, the 2016 Proposed Gas Transmission Integrity Rules provide new criteria for evaluating and addressing all pipeline anomalies, regardless of class location and regardless of whether the pipeline segment is in an HCA.

As PHMSA notes in the ANPRM, current class change special permits include inspection area requirements upstream and downstream of class chase segments.[73] This special permit requirement does not have a technical basis. Operators have agreed to inspect areas upstream and downstream of class change segments in exchange for the special permit allowance. However, now that PHMSA is considering regulations to extend integrity assessment requirements outside of HCAs, special permit inspection areas are no longer appropriate or necessary to ensure pipeline safety. If PHMSA believes the "inspection area" concept should be retained as part of the integrity assessment method for managing class location changes, PHMSA must provide data to demonstrate the connection between the integrity of a class change segment and the pipeline 25 miles upstream and downstream.

Other topics in question 4c

Aside from inspection areas, the Associations have addressed the other topic raised in question 4c earlier in Section IV.

[73] Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. at 36,865.

F. The "traceable, verifiable, and complete" standard should only apply to the record or records necessary to confirm MAOP.

Q5 – As it is critical for operators to have traceable, verifiable, and complete (TVC) records to perform IM, should operators be required to have TVC records as a prerequisite for performing IM measures on segments instead of replacing pipe when class locations change? Why or why not?

5a. – If so, what records should be necessary and why? Should records include pipe properties, including yield strength, seam type, and wall thickness; coating type; O&M history; leak and failure history; pressure test records; MAOP; class location; depth of cover; and ability to be in-line inspected?

5b. – If operators do not have TVC records for affected segments and TVC records were a prerequisite for performing IM measures on pipeline segments in lieu of replacing pipe, how should those records be obtained, and when should the deadline for obtaining those records be?

The Associations recommend that the recordkeeping standard of "traceable, verifiable, and complete" (TVC) only apply to the record or records necessary to confirm MAOP. When an operator uses the proposed integrity assessment method for managing class location changes, additional material property data may be needed to conduct anomaly evaluation and remediation calculations. Where material property records are not available, PHMSA has proposed appropriate options in the 2016 Proposed Gas Transmission Integrity Rules which the GPAC has endorsed. Operators will be required to use values based on current MAOP or similar vintage pipe, specific conservative values[74] or values determined using the material verification process at proposed § 192.607 (as approved by the GPAC on December 17, 2017).[75] There is no need to establish prohibitions from using integrity assessments for managing class location changes due to missing records when PHMSA has already developed approaches for addressing missing pressure test and material records.

PHMSA should limit the application of "traceable, verifiable, and complete" to MAOP records.

While the Associations agree that operators should have an MAOP record or records that meets the TVC recordkeeping standard, a broader application of TVC is unreasonable, impractical, and not cost effective.[76] When this recordkeeping standard was first introduced, it was limited to MAOP records. In 2010, the NTSB included TVC in two of its safety recommendations to the Pacific Gas & Electric Company

[74] GPAC Meeting Final Voting Slides at 6, 19 (Mar. 26-28, 2018).
[75] GPAC Meeting Final Voting Slides at 1-3 (Dec. 14, 2017), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=931.
[76] When the Associations refer to the TVC standard, it is referring to the definitions of TVC that PHMSA included in its 2012 Advisory Bulletin. *See* Pipeline Safety: Verification of Records, 77 Fed. Reg. 26,822 (May 7, 2012). To date, PHMSA has not codified a definition of "traceable, verifiable, and complete."

covering MAOP records.[77] Similarly, PHMSA's advisory bulletins in 2011 and 2012 limited the application of this recordkeeping standard to MAOP records[78] and the records review requirements outlined in Section 23 of the 2011 Act are focused on MAOP.[79]

Numerous stakeholders, including the Associations, provided feedback on whether the TVC standard should apply to other pipeline records as part of the 2016 Proposed Gas Transmission Rules.[80] In those proposed rules, PHMSA proposed to expand the application of TVC to all "records that demonstrate compliance with Part 192" (Proposed § 192.13(e)(2)).[81] Many commenters expressed concern with this proposal stating that such a broad application was unnecessary and impracticable.[82]

In 2018, the GPAC voted to remove the proposed § 192.13(e) finding that it was not practicable, reasonable or cost effective.[83] The GPAC members also engaged in a lengthy discussion of whether TVC should be applied to MAOP records only.[84] Industry members questioned whether it was reasonable and necessary to require all records to meet the TVC recordkeeping standard.[85] Government members

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[77] NTSB, Safety Recommendation*,* P-10-2, P-10-3 (Jan. 3, 2011), http://www.ntsb.gov/safety/safety-recs/recletters/P-10-002-004.pdf.

[78] Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation, 76 Fed. Reg. 1504 (Jan. 10, 2011); Pipeline Safety: Verification of Records, 77 Fed. Reg. 26,822, 26,823 (May 7, 2012) (Specifically, the 2012 Advisory Bulletin reminded pipeline operators to verify their MAOP records and "take action as appropriate to assure that all MAOP and MOP are supported by records that are traceable, verifiable, and complete.").

[79] 49 U.S.C. § 60139 (2017).

[80] *See* Comments of the Interstate Natural Gas Association of America at 35-47, No. PHMSA-2011-0023, (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0407; Comments of the American Gas Association on the Safety of Gas Transmission and Gathering Pipeline Proposed Rule at 32-33, No. PHMSA-2011-0023 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0339; Comments of the Delmarva Power & Light Co. on the Safety of Gas Transmission and Gathering Pipelines Proposed Rule at 8 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0344; Comments of Kinder Morgan, Inc. on the PHMSA Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Proposed Rule at 4, PHMSA-2011-0023 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0349; Comments of Spire, Inc. on the Safety of Gas Transmission and Gathering Pipelines Proposed Rule at 6-7 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0367.

[81] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. at 20,808, 20,828, Proposed § 192.13(e)(2) ("Each operator must make and retain records that demonstrate compliance with this part. (1) Operators of transmission pipelines must keep records for the retention period specified in appendix A to part 192. (2) Records must be reliable, traceable, verifiable, and complete.").

[82] Comments of the American Gas Association on the Safety of Gas Transmission and Gathering Pipeline Proposed Rule at 5, 28, 30, No. PHMSA-2011-0023 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0339; Comments of GPA Midstream Association at 27, PHMSA-2011-0023 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0290; Comments of Washington Gas Light Co. on the Proposed Rule on Safety of Gas Transmission and Gathering Pipelines at 8 (Addendum), PHMSA-2011-0023 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0337.

[83] GPAC Meeting Final Voting Slides at 6 (Mar. 2, 2018), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=939.

[84] GPAC Meeting Tr. 227:14-243:8 (Mar. 27, 2018), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=971.

[85] *Id.* 228: 1-12 (J. Andrew Drake, Vice President, Asset Integrity and Technical Services, Enbridge Gas Transmission and Midstream).

expressed concern that a company may have "good data" but could potentially not meet the "very high TVC standard"[86] and recommended that the Agency add language to clarify that TVC only applies to MAOP records.[87] PHMSA noted that "we've been down this road together dealing with that phrase, and it's all been within the realm of establishing MAOP."[88] In subsequent discussions, PHMSA clarified that all records do not necessarily need to meet the TVC standard but should be credible.[89] Given this history, it is difficult to understand the Agency's renewed focus on TVC records as a prerequisite to applying integrity management principles. As discussed on the record in public meetings and in comments to the docket, TVC should only apply to the record or records needed to demonstrate MAOP, in accordance with § 192.624. For example, a pressure test chart that includes test data, pipe location and relevant pipe attributes meets the requirement for a TVC pressure test record.

The Associations do not agree with PHMSA's statement in the ANPRM that "it is critical to have <u>traceable, verifiable, and complete</u> records to perform IM…"[90] The Part 192 regulations do not currently require an operator to have any records meeting the TVC standard, and PHMSA has not proposed to amend 49 C.F.R. § 192.924, the Integrity Management Program recordkeeping requirement, to include a TVC requirement. Data gathering and analysis are critical features of an integrity assessment program, and an operator has an obligation to consider whether necessary information is lacking in conducting the continual process of evaluation and assessment to maintain a pipeline's integrity. Although some of the records PHMSA references in ANPRM question 5(a) could be relevant to addressing a class location change, none of those records should be subject to the TVC standard (with the exception of the record or records needed to demonstrate MAOP).

It is also difficult to determine how PHMSA would apply or enforce a TVC standard for the documents identified in the ANPRM, other than the record or records needed to demonstrate MAOP.[91] PHMSA has not provided any evidence of a specific problem with the records and data operators currently use to support pipeline corrosion control, maintenance, or integrity management activities. Operators have amassed a large amount of information that is successfully employed to support these activities and other tasks that are well beyond MAOP establishment/reconfirmation. If PHMSA applies the TVC requirement to these records, such a change could create confusion as to whether existing records were still valid. As the Associations and other industry commenters explained during the rulemaking process for the 2016 Proposed Gas Transmission Integrity Rules, Part 192 does not currently require operators to keep or maintain TVC records, and that standard cannot be applied retroactively to require documentation of activities that operators previously conducted on existing gas pipeline facilities.[92] Given that prohibition,

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[86] *Id.* at 228:17; 229:13 (Sara W. Longan, Executive Director, North Slope Science Initiative, Bureau of Land Management).
[87] *Id.* at 231:1-13 (Stephen E. Allen, Director, Pipeline Safety Division, Indiana Utility Regulatory Commission) ("Yes. I think that makes an awful lot of sense to go ahead and add something in here that says that, you know, these records are related to records that were created or associated with, you know, the pressure.").
[88] *Id.* at 230:14-16 (Alan Mayberry, Associate Administrator for Pipeline Safety).
[89] GPAC Meeting Tr. 9:16-19 (Mar. 28, 2018)(Alan Mayberry, Associate Administrator for Pipeline Safety).
[90] Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. at 36,869-870 (emphasis added).
[91] *Id.* at 36, 869.
[92] Comments of the Interstate Natural Gas Association of America at 41-44, No. PHMSA-2011-0023, (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0407; Comments of the American Petroleum Institute at 105-112, No. PHMSA-2011-0023, (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-

it is difficult to envision the circumstances where PHMSA could fairly require operators to produce such documentation as a condition of managing class location changes, particularly in the near term.

PHMSA has never provided any guidance or proposed regulatory text regarding the meaning of TVC outside of MAOP records. For some of the data/information mentioned in question 5(a) (e.g. depth of cover, O&M history, leak and failure history), it is entirely unclear what a "TVC" record would look like. Broadly applying TVC, particularly without a codified definition in regulatory text, would inevitably create confusion and disagreement between operators and regulators over whether any specific records meets this unique standard. If PHMSA excludes pipelines from the integrity assessment method for managing class location changes based on a broad application of the TVC standard, such an approach would drastically decrease the value of this proposed update to the class location change regulations and potentially strain PHMSA's inspection and enforcement resources to determine which operators met the criteria.

Operators with missing records should not be prohibited from using integrity assessments to manage class location changes, as PHMSA has proposed options to address record gaps.

PHMSA developed several processes to address missing data or records as part of its 2016 Proposed Gas Transmission Integrity Rules. While the GPAC voted to modify these provisions during its review of the NPRM, the proposals are largely intact. PHMSA should continue to support these approaches as it considers developing an integrity assessment method for managing class location changes. There is no need to establish prohibitions from using integrity assessments to manage class location changes due to missing records when PHMSA has already created an approach to handle missing records.

To the extent that an operator is missing a record or records to confirm MAOP, those documents will be obtained through the MAOP reconfirmation process.[93] PHMSA's 2016 Proposed Gas Transmission Integrity Rules will require operators to reconfirm MAOP for segments operating above 30% of SMYS in all class 3 and 4 areas, HCAs and certain MCAs without TVC pressure test records (proposed § 192.624(a)). For operators seeking to use the integrity assessment method to manage a class location change on a segment that requires MAOP reconfirmation under § 192.624(a), PHMSA should require operators to reconfirm the MAOP using one of the methods required in proposed § 192.624(c) (as modified by the recommendations of the GPAC) **within 24 months** of identifying the change in class location. For such class change segments, MAOP reconfirmation should be based on the test factor *for the installed date and class location at the time of installation*.

2011-0023-0381; Comments of the Delmarva Power & Light Co. on the Safety of Gas Transmission and Gathering Pipelines Proposed Rule at 7 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0344; Comments of Dominion East Ohio at 7, No. PHMSA-2011-0023 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0283; Comments of the American Gas Association on the Safety of Gas Transmission and Gathering Pipeline Proposed Rule at 15-16, No. PHMSA-2011-0023 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0339; Comments of the PECO Energy Company on the Safety of Gas Transmission and Gathering Pipeline Proposed Rule at 9, No. PHMSA-2011-0023 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0399.

[93] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. at 20,833, Proposed 49 C.F.R. § 192.624.

In the ANPRM, PHMSA references material property records in its list of records that an operator may be required to produce prior to being eligible to use integrity assessments to address a class location change. Material property records are primarily used to conduct anomaly response calculations and are generally not used to demonstrate MAOP (because a pressure test or operating history record is generally used to demonstrate MAOP). During the GPAC meetings to review the 2016 Proposed Gas Transmission Integrity Rules, PHMSA and the GPAC agreed that material property data should be collected **as needed** to support anomaly response calculations, in accordance with the anomaly response and repair criteria in proposed § 192.713 and § 192.933. PHMSA and the GPAC agreed on several options that could be safely used to inform anomaly response calculations when material property records are unavailable. Operators will be required to use values based on current MAOP or similar vintage pipe, specific conservative values[94] or values determined using the material verification process at proposed § 192.607 (as approved by the GPAC on December 17, 2017). [95] Therefore, no class location change-specific data gathering requirements are needed to support anomaly response and repair calculations.

[94] GPAC Meeting Final Voting Slides. at 6, 19 (Mar. 26-28, 2018).

[95] GPAC Meeting Final Voting Slides at 1-3 (Dec, 14, 2017).

G. <u>The 2016 Proposed Gas Transmission Integrity Rules prescribe sufficient requirements to ensure safety in class location change segments. Additional preventative and mitigative measures are unnecessary.</u>

Q9 – Should any additional pipeline safety equipment, preventative and mitigative measures, or prescribed standard pipeline predicted failure pressures more conservative than in the IM regulations be required if operators do not replace pipe when class locations change due to population growth and perform IM measures instead? Why or why not?

In order to identify and prevent potential failure mechanisms, the 2016 Proposed Gas Transmission Integrity Rules prescribe requirements for threat evaluations, integrity assessments and anomaly investigation and remediation. These requirements are more than sufficient to ensure safety in lieu of current requirements to reduce pipe stress (through the installation of new pipe or reducing operating pressure) when a class location change occurs. It is unnecessary to require additional preventative and mitigative measures specifically for segments that have experienced a class location change.

The class location change requirements were intended for a specific purpose – to ensure an appropriate safety margin when there is population growth around an existing pipeline. Historically, pipe replacement, pressure reduction or pressure testing (where allowed for one-class changes) accomplished this objective. Installing thicker/stronger pipe or reducing pressure mitigates, to some extent, the effects of time-dependent and resident threats that could decrease a pipeline segment's margin of safety. This can now also be effectively accomplished using modern integrity assessment programs.

In developing an integrity assessment method for managing class location changes, PHMSA must recognize that the class location change regulations in and of themselves were never intended as a catch-all requirement to address every potential safety concern on a pipeline system or address all aspects of risk. For a segment that experiences a class location change, the class change regulations are but one area of the code that applies to that pipeline. All of the other applicable requirements and programs still apply to that segment, regardless of the class change. Various code requirements address operations and maintenance, corrosion control, surveying, patrolling, procedures, operator training and qualification, and many other important activities that do not need to be addressed specifically in the class location change regulations.

For example, all pipelines in class 3 and 4 areas already have requirements for more frequent patrolling and leak detection surveys, per § 192.705 and § 192.706. As another example, the 2016 Proposed Gas Transmission Integrity Rules prescribes more conservative requirements for anomaly response calculations in more populated areas. These additional requirements are appropriate to enhance safety in higher population areas, regardless of whether the pipeline was built before or after population growth occurred.

Therefore, it would be unnecessary and inappropriate to apply new requirements for preventative and mitigative measures specifically to segments that have experienced a class location change, on top of the existing requirements in HCAs and the new requirements in PHMSA's 2016 Proposed Gas Transmission Integrity Rules. The current options for managing class location changes do not, in and of themselves, protect against every threat. Neither will recurring integrity assessments, in and of themselves – it is the purpose of the entire part 192 code to ensure public safety by addressing all threats to safe pipeline operations.

9a. – Should operators be required to install rupture-mitigation valves or equivalent technology? Why or why not?

Historically, installing remote or automatic valves has not been a class location change special permit requirement – there is no mention of this equipment in RSPA's 2004 notice regarding class location change special permits, the associated guidance document[96] or the current class location change special permit template, which was issued in 2012.[97] Nor is installing remote or automatic valves required in PHMSA's subpart O regulations for gas transmission pipelines in HCAs. PHMSA has provided no evidence or discussion regarding why a remote/automatic control valve requirement would be necessary to achieve the intended purpose of the class location change requirements – to ensure an appropriate safety margin when there is population growth around an existing pipeline.

PHMSA commissioned Oak Ridge National Laboratory ("Oak Ridge") to study the installation of automatic and remote valves on natural gas and hazardous liquid pipelines.[98] Oak Ridge determined that "site-specific parameters that influence risk analyses and feasibility evaluations often vary significantly from one pipeline segment to another" and "[c]onsequently, the technical, operational, and economic feasibility and potential cost benefits of installing ASVs and RCVs in newly constructed or fully replaced pipelines need to be evaluated on a case-by-case basis."[99]

9b. – Should operators be required to install SCADA systems for impacted pipeline segments? Why or why not?

The Associations believe that SCADA systems are in place on the vast majority of gas transmission pipelines today. The design and capabilities of these systems vary based on the specific application, but the Associations are not aware of any major gas transmission pipeline systems that operate without SCADA assistance. Historically, SCADA has not been addressed in class location change special permits.[100] PHMSA has provided no evidence or background to explain why connecting SCADA-related requirements to class location changes would be necessary or appropriate.

[96] Pipeline Safety: Development of Class Location Change Waiver Criteria, 69 Fed. Reg. 38,948 (June 29, 2004).
[97] 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.
[98] Oak Ridge National Laboratory, Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety (2012), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/16701/finalvalvestudy.pdf.
[99] *Id.* at xix.
[100] Pipeline Safety: Development of Class Location Change Waiver Criteria, 69 Fed. Reg. 38,948 (June 29, 2004).

H. Class location change data requested by PHMSA

Q8 – What is the amount of pipeline mileage per year being replaced due to class location changes for pipelines: 1) greater than 24 inches in diameter, 2) 16-24 inches in diameter, and 3) less than 16 inches in diameter?

8a. – Of this mileage, how much is being replaced due to class locations changing when additional structures for human occupancy are built near clustered areas, if operators are using the cluster adjustment to class locations per § 192.5(c)(2)?

8b. – At how many distinct locations are pipe replacements occurring due to class location changes and that involve pipe with these diameters?

8c. – What is the average amount of pipe (in miles) being replaced and cost of replacement at the locations described in question 8b. and for these diameter ranges due to class location changes?

The Associations collected and aggregated operator data for the mileage, number of distinct segments and the costs of class location changes in **Table 2** below. The data includes class changes that occurred for any reason (population growth, development of a new cluster, construction of a class 3 site, etc.).[101] Table 2 reflects data from operators representing over 160,000 miles of natural gas transmission pipelines that responded to the Associations' data request.

AGA, API and INGAA previously estimated that gas transmission pipeline operators incur annual costs of $200 – $300 million nationwide replacing pipe solely to satisfy the current class location change regulations.[102] Table 2 indicates that the actual annual costs may be towards the upper end of the Associations' previous estimate. Table 2 indicates that the surveyed operators are cumulatively spending approximately $170 million annually on class location change pipe replacements. Extrapolating this data to the almost 300,000 miles of natural gas transmission pipelines nationwide yields an industry-wide estimate of over $300 million annually for class location change pipe replacements.

As discussed in greater detail in Section III above, Table 2 indicates that a tremendous amount of resources is spent performing replacement activities on a small amount of mileage. The Associations' data indicates that an average of only 68 miles of pipe are being replaced each year. The length of the class change pipe replacement is not the main driver of the costs. Ultimately, the inordinate total pipe replacement costs result from individual class location changes requiring replacements of many small individual segments of pipe. The data in Table 2 indicates that the average class location change segment is less than half of a mile in length.

[101] 49 CFR § 192.5(b)(3)(ii)
[102] Comments of AGA, API and INGAA on the Department of Transportation Notification of Regulatory Review at 3, No. OST-2017-0069 (November 9, 2017), https://www.regulations.gov/document?D=DOT-OST-2017-0069-1504.

What is the mileage of pipe and number of distinct segments being replaced each year due to class changes? What is the cost of these replacements?	2011			2012			2013			2014		
	Mileage	Segments	Cost	Mileage	Segments	Cost	Mileage	Segments	Cost	Mileage	Segments	Cost
Pipeline diameter greater than 24 in.	28	76	$120,088,741	25	66	$105,322,762	26	55	$106,677,291	21	62	$99,154,485
16-24 in.	13	31	$62,632,889	9	27	$38,025,440	23	87	$56,752,041	16	49	$74,197,122
Less than 16 in.	1	5	$4,505,924	1	3	$3,051,504	3	5	$8,803,516	2	3	$2,951,199
Total	**43**	**112**	**$187,227,554**	**36**	**96**	**$146,399,706**	**51**	**147**	**$172,232,848**	**38**	**114**	**$176,302,806**

What is the mileage of pipe and number of distinct segments being replaced each year due to class changes? What is the cost of these replacements?	2015			2016			2017			Expected future annual rate		
	Mileage	Segments	Cost	Mileage	Segments	Cost	Mileage	Segments	Cost	Mileage	Segments	Cost
Pipeline diameter greater than 24 in.	22	51	$117,394,889	26	57	$115,344,784	20	44	$105,847,320	26	60	$126,826,058
16-24 in.	12	23	$40,983,083	9	24	$38,360,782	12	42	$54,766,631	19	47	$76,942,778
Less than 16 in.	5	5	$8,350,620	7	5	$5,963,684	1	3	$2,623,519	13	6	$17,757,752
Total	**39**	**79**	**$166,728,592**	**10**	**86**	**$159,669,250**	**34**	**89**	**$163,237,470**	**57**	**113**	**$221,526,588**

***Table 2**: This table summarizes historical and expected future class location change pipe replacement data from the Associations' members. Operators representing over 160,000 miles of natural gas transmission pipeline responded to the Associations' data request. The question posed was: "For your company, what is the mileage of pipe and number of distinct segments being replaced each year due to class changes? What is the cost of these replacements?"*

I. Miscellaneous topics

Q7 – For all new and replaced pipelines, to what extent are operators consulting growth and development plans to avoid potentially costly pipe change-outs in the future?

In general, operators consult definitive and concrete development plans when designing new pipelines to avoid a class location change. As demonstrated in these comments, operators have a vested interest in avoiding class location changes. However, operators do not make class location design decisions based on speculative development plans. For example, if a developer is in the initial stages of considering a new building that might be constructed several years in the future, a pipeline company may rightly choose not to modify the class location design factors for a pipeline project that is underway. The specific location of that new third-party building could change dramatically throughout planning and siting, or that build may never be built.

PHMSA has not presented any evidence to demonstrate that operators are inadequately considering growth and development plans when designing new pipelines. The Associations' interest in class location changes is not about changing the design factors for pipelines that will be built in the future. Historically, class location changes occur due to growth over many decades. It is the Associations' understanding that the newest pipe segment currently operating under a class location change special permit was built in 1993. The permit was issued in 2010, over 15 years after construction. Clearly, that operator sufficiently planned for reasonably foreseeable development, with no special permit needed for over a decade.

Q10 – Should there be any maximum diameter, pressure, or potential impact radius (PIR) limits that should disallow operators from using IM principles in lieu of the existing requirements when class locations change? For instance, PHMSA has seen construction projects where operators are putting in 42-inch-diameter pipe designed to operate at up to 3,000 psig. The PIR for that pipeline would be over 1,587 feet, which would mean the total blast diameter would be more than 3,174 feet.

The PIR calculation is a consequence screening methodology used to prioritize pipelines for inclusion in risk management programs based on the potential number of structures that could be impacted by a theoretical pipeline incident. It would be inappropriate to establish diameter, pressure or PIR-based limits on the integrity assessment method that do not apply to other methods. Such limits would be counter to safety. This question appears to be based on the flawed assumption that reducing operating stress is safer than an integrity assessment-based solution for managing class location changes. This is not the case.

For example, a pipeline with a large PIR in a remote (class 1) area may not be required to conduct recurring integrity assessments, even after the 2016 Proposed Gas Transmission Integrity Rules are implemented. However, if a class 1 to 3 change occurs on such a line and the operator chooses the proposed integrity assessment method to manage the class change, then the integrity assessment method would require initial integrity assessments within two years, with recurring assessments after that. These assessments on the class change segment could identify threats not only to that segment, but to the broader pipeline system. This is a much more effective way to manage the long-term integrity of this pipeline, rather than simply reducing operating stress at the specific place in the line that had a class change.

PHMSA also appears to be mis-applying the PIR concept. PIR was not intended to be used to establish prescriptive limits for where integrity assessments could be safely applied. No technical standards or PHMSA regulations currently limit operators' decision making based purely on the *size* of the PIR. It is the *number of structures* within the PIR that is relevant, and existing and pending PHMSA regulations require operators to use that information to determine where and how often to apply integrity assessments, among other risk management program elements. There is no current code requirement to reduce operating stress pipe based on PIR – design requirements are based on class location.

Finally, a review of PHMSA incident data indicates that there is no correlation between higher operating stresses and incident rates. A summary of this review is provided under "Miscellaneous Topics" below (*see* "PHMSA's focus on pipe stress as an indicator of pipeline safety is misplaced").

Additional topics that were not directly raised in PHMSA's ANPRM questions

Expedited interim process

While PHMSA considers developing a new regulatory option for managing class location changes through this ANPRM, the Agency should consider a temporary expedited process for allowing operators to implement an integrity assessment program to manage class changes. For every year that passes without an update to this antiquated requirement, hundreds of millions of dollars of potential investment in modern technologies and processes is passed over in lieu of lower-value pipe replacements. This equates to well over a billion dollars in lost pipeline safety enhancements during the approximately fifteen years that PHMSA has been considering this critically-needed update.[103]

Uprating and restoration of prior MAOP

PHMSA should ensure that operators complying with the new integrity assessment method for managing class location changes can still uprate their MAOP in accordance with subpart K. Operators who have previously reduced operating pressure to comply with § 192.611 should be allowed to come into compliance with the new integrity assessment method, and then restore their prior MAOP. This is consistent with existing § 192.611(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." In Section V below, the Associations recommend additions to § 192.611(d) to address the restoration of prior MAOP following the implementation of the integrity assessment method for managing class location changes.

[103] PHMSA has previously estimated that pipe replacements associated with class location changes can cumulatively result in at least $1 billion over a 20-year period. *See* Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines), 68 Fed. Reg. at 69,802, 69,813 ("Operators typically replace pipeline when population increases, because reducing pressure to reduce stresses reduces the ability of the pipeline to carry gas. . . . Replacing pipeline, however, is very costly. Providing safety assurance in another manner, such as by implementing this rule, could allow RSPA/OPS to waive some pipe replacement. RSPA/OPS estimates that such waivers could result in a reduction in costs to industry of $1 billion over the next 20 years, with no reduction in public safety.").

Existing special permits

PHMSA's proposed change to the regulations for managing class location changes should not affect the validity of existing special permits. However, operators should be able to retire existing special permits upon achieving compliance with the integrity assessment method for managing class location changes.

Annual reporting

The Associations would support PHMSA revising the gas transmission annual report to accommodate the new regulation for managing class location changes. Each operator could report annually on its cumulative class location change mileage and what proportion of that mileage is being managed through replacement, pressure reduction, pressure testing, integrity assessment program, special permit or "to be determined," for recent class changes.

That being said, current notification and reporting requirements for class location change special permit-related activities are far beyond what is useful and required by part 192. It is difficult to understand the value of notifying PHMSA about every integrity assessment, anomaly investigation, CIS conducted, CP remediation, etc. Operators conduct these activities throughout their pipeline system as a daily course of business, without the need to notify PHMSA prior to each work activity. Additionally, operators are required to submit onerous data sets every year. Much of the required information is duplicative from previous submittals.

Odorization in class 3 & 4 areas

While the action required under § 192.611 following a class location change is the primary focus of this ANPRM, class changes do affect other pipeline safety regulatory requirements.

For example, § 192.625 requires the odorization of gas transmission pipelines operating in class 3 and 4 areas, unless exemptions apply. A class location change could cause a line that currently is not odorized to require odorization, particularly if the class change segment is near the end of the pipeline. Many natural gas users, particularly industrial users, cannot accommodate odorized gas.

The odorization of natural gas is intended to mitigate the consequence of leaks by providing an early indicator of the leak. However, operators may be able to implement other preventative and mitigative actions, such as increased leak surveying, to provide the early indication of a leak. There are also numerous technologies in development to further assist operators to identify leaks on their system without relying upon the sense of smell.

PHMSA's focus on pipe stress as an indicator of pipeline safety is misplaced.

The class location change requirements were intended for a specific purpose – to ensure an appropriate safety margin when there is population growth around an existing pipeline. Installing thicker/stronger pipe or reducing pressure mitigates, to some extent, the effects of time-dependent and resident threats that could decrease a pipeline segment's margin of safety. This can now also be effectively accomplished using modern integrity assessment programs.

However, in the ANPRM, PHMSA asserts that "it is important to decrease pipe stresses in areas where there is the potential for higher consequences or where higher pipe stresses could affect the safe operation of a pipeline in larger-populated areas." [104] In the context of class location changes, the focus on pipe stress as indicator of the likelihood of a pipeline failure reflects outdated thinking.[105] Today, corrosion control, surveying and patrolling, integrity assessments, anomaly evaluation and repair, and other operations and maintenance programs have much more bearing on pipeline safety than pipe stress.

PHMSA has previously acknowledged that pipe stress has a limited role in impacting pipeline safety. PHMSA's 2008 "alternate MAOP" rulemaking for gas transmission pipelines notes that, "modern maintenance practices, if consistently followed, significantly reduce the risk that corrosion, or other defects affecting pipeline integrity, will develop in installed pipelines. Most recently, operators' development and implementation of integrity management programs have increased understanding about the condition of pipelines and how to reduce pipeline risks." [106] PHMSA concludes that, "[w]ith the benefit of operating experience with pipelines, it seems clear that operating pressure plays a less critical role in pipeline integrity and failure consequence than other factors within the operator's control."[107] Similarly, the regulations governing hazardous liquid pipelines do not include the class location concept.

The Associations analyzed the most recent eight years (2010 to 2017) of incident and annual report data reported to PHMSA for gas transmission and gathering pipelines to evaluate the relationships between pipe stress (% SMYS), integrity assessments and class location.

For purposes of this analysis, the Associations selected incidents that meet the following criteria on the PHMSA F7100.2 incident report form:

- The release was unintentional (A.8) and was natural gas (A.9)
- The pipeline was onshore (B.1), the incident was on the right-of-way (B.10) and the part of system involved was onshore pipeline, including valve sites (C.2)
    - Excluding offshore incidents and those on operator-controlled property. Offshore pipelines and piping in operator-controlled property are generally not affected by class location change and have different integrity assessment programs than onshore pipelines.
- The item involved was pipe body or seam (C.3)
    - Excluding girth, butt, and fillet welds, valves, compressors, other misc. equipment. These failures are generally unrelated to pipe stress.
- The pipeline was carbon steel (C.5)

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[104] Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. at 38,682.
[105] In previous comments related to the pending gas transmission integrity rules, the Associations have noted that, in general, pipelines operating below 30% of SMYS present significantly reduced risk because they generally fail in the leak mode, rather than rupture. The current class location change regulations only require action (pipe replacement, pressure reduction, etc.) if the pipe is operating above 40% of SMYS. The discussion in this section is focused on pipelines operating above 40% of SMYS.
[106] Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines, 73 Fed. Reg. 62,148, 62,148 (Oct. 17, 2008).
[107] *Id.*

    - Excluding plastic and other non-steel materials

- The type of incident was a leak with cracks, or rupture
    - Excluding mechanical punctures, pinhole leaks, connection failures, seal / packing failures, and misc. causes. These failures are generally unrelated to pipe stress.

The above criteria identified 16% of the reported incidents for the past eight years (124 of 790) that might have been caused by factors related to the pipe stress or integrity assessment practices on the pipeline right-of-way. Of the incidents that met these criteria, the majority were: Material Failure of Pipe or Weld (MWF) – 44% of incidents, Corrosion – 27%, Excavation Damage – 13%, and Natural Force – 7%. All other causes combined made up less than 10% of the incidents. Thus, the remainder of the analysis was focused on these top 4 causes.

The Associations then determined the prevalence of these incidents by cause and the operating stress range (% SMYS) of the pipeline at the location of failure. The Associations then compared that incident prevalence (by cause and % SMYS) to the proportion of total pipeline mileage which is reported to operate at each % SMYS stress range (part K of the annual report). The incident rates by cause and % SMYS range are shown in **Figure 1** below by the skinny bars, and the pipeline inventory operating at that % SMYS range is shown by the wide opaque bar. Any skinny bar which is taller than the wide bar indicates an incident cause which is over-represented at that stress range (i.e. it has a higher percentage of incidents at that % SMYS range than there is pipe operating at that % SMYS range overall). Conversely, any skinny bar which is shorter than the wide bar indicates an incident cause which is under-represented at that % SMYS range of pipeline (i.e. there are fewer incidents due to that cause in that % SMYS range than would be expected).

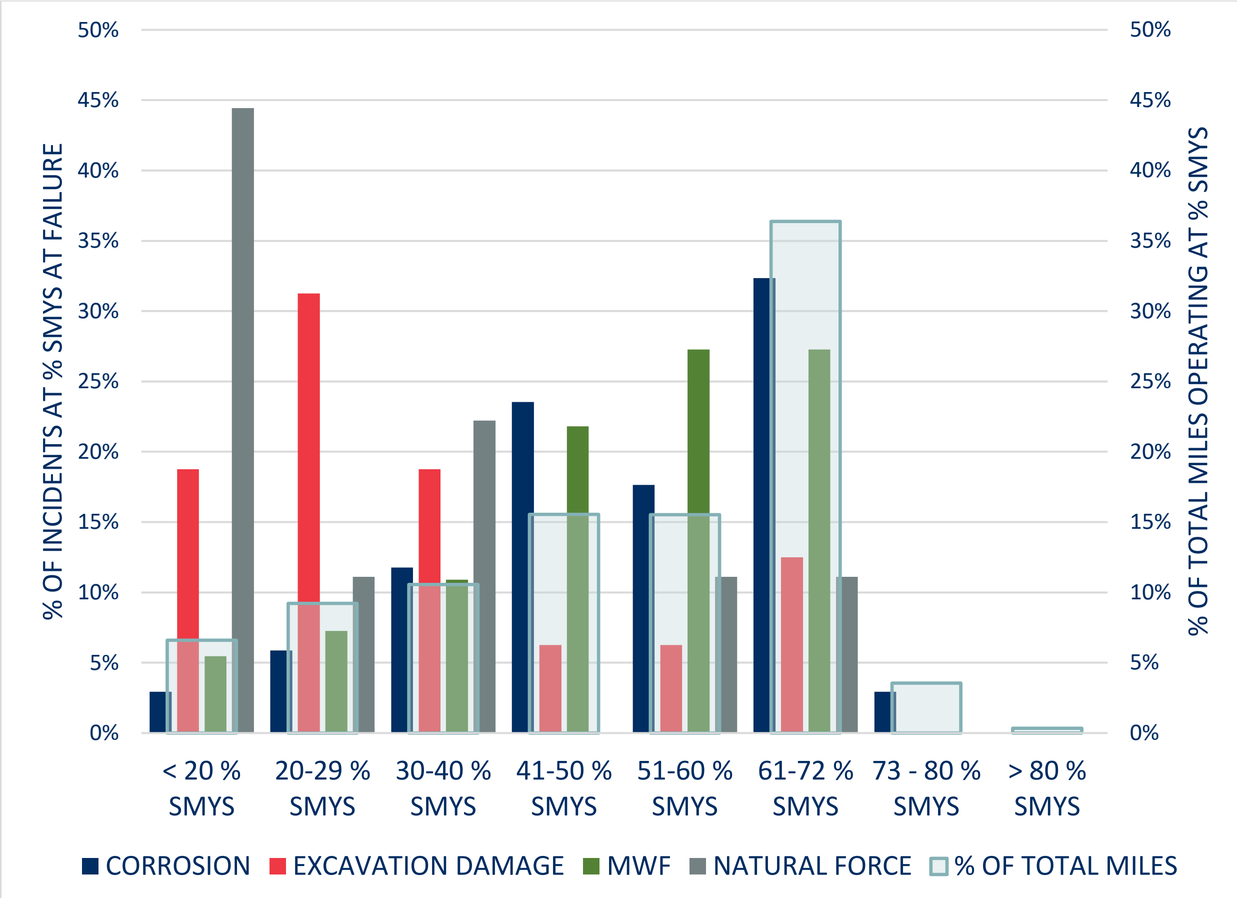

Figure 1*: For a variety of incident causes that relate to pipe stress and integrity assessment, incident frequencies are under-represented for pipelines operating at higher stress levels (61+% SMYS) and over-represented at lower-stress levels.*

As the graph indicates, each incident cause is under-represented for pipelines operating at higher stress levels (61+% SMYS) but is over-represented at lower stress levels. For example, 36% of pipeline mileage is reported to operate between 61 and 72% of SMYS, but only 27% of MWF incidents occur at that % SMYS stress range. The same applies for corrosion, excavation damage, and natural force incidents. Each of these incident causes is under-represented on a mileage basis at % SMYS levels of 61% and higher. This indicates that these incident causes are currently being effectively managed, even at higher stress levels.

The Associations also analyzed the prevalence of these incidents by class location, compared to the pipeline mileage nationwide in each class location. The results are in **Figure 2** below. This analysis indicated that the frequency of corrosion, material weld failure and natural force incident causes is not significantly impacted by class location (with the number of incidents being proportional to the mileage in each class location). The only cause which appears to be related to class location is excavation damage, which is over-represented in Class 2 and 3 areas. This is not surprising, as excavation, and excavation damage, is more likely in populated areas than in sparsely populated areas.

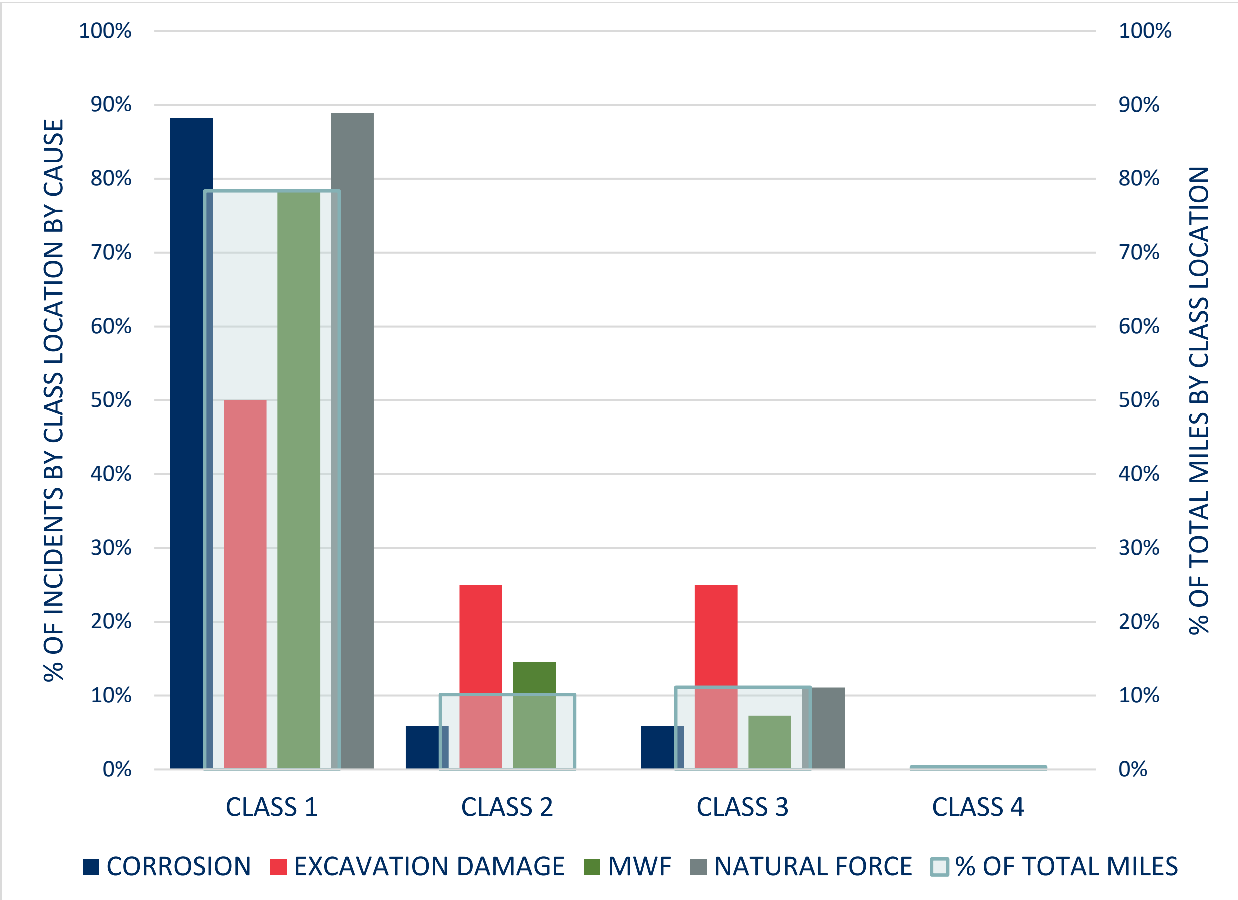

Figure 2: *The frequency of corrosion, material weld failure and natural force incident causes is not significantly impacted by class location.*

In summary, the Associations' analysis would indicate:

1. The vast majority of incidents reported on gas transmission and gathering lines are either unrelated to pipe stress or at locations other than the pipeline right-of-way (class location changes generally pertain to the pipeline right of way).
2. On the pipeline right-of-way, incidents caused by threats that may be related to pipe operating stress are less prevalent at higher operating stresses. This indicates that pipeline operators are effectively managing the causes of incidents which may be related to pipe operating stress and could affect the public.
3. On the pipeline right-of-way, excavation damage is the only incident cause that seems to be related to class location. Excavation damage is addressed through damage prevention, public awareness and patrolling regulations, not through the class location change requirements.

PHMSA notes in the preamble to the ANPRM that, "Whereas overtime the safety margins that class locations provide can be reduced due to corrosion or other types of pipe degradation, IM requirements provide a continuing minimum safety margin."[108] The Associations concur with this statement.

[108] Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. at 36,868.

V. Proposed Regulatory Text for Integrity Assessment-based Management of Class Location Changes

The Associations offer the following example of how an integrity assessment method could be incorporated into the existing regulations for managing class location changes. The Associations' proposed additions and modifications to the existing code language are indicated in **red**.

PHMSA should finalize the 2016 Proposed Gas Transmission Integrity Rules and update the class location change regulations at the same time or promptly thereafter. However, if PHMSA is delayed in finalizing any aspect of the 2016 Proposed Gas Transmission Integrity Rules that is needed to implement the integrity assessment method for managing class location changes, PHMSA can still incorporate the needed requirements directly into § 192.611, based on the GPAC discussions and voting materials for the 2016 Proposed Gas Transmission Integrity Rules.

§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) ***Previous Test.*** 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) ***MAOP Reduction.*** 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) ***New Subpart J Pressure Test.*** 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) *Integrity Assessment Program.* The segment involved must be included in an integrity assessment program according to the following criteria:

(i) *Hoop Stress.* The hoop stress corresponding to maximum allowable operating pressure of the segment involved must not exceed 80 percent of SMYS in Class 2 locations, 72 percent of SMYS in Class 3 locations, or 60 percent of SMYS in Class 4 locations.

(ii) *MAOP reconfirmation.* If the segment involved requires maximum allowable operating pressure reconfirmation under §192.624(a), the operator must reconfirm the maximum allowable operating pressure of the segment involved using one of the methods prescribed in §192.624(c) within 24 months of the change in class location. Maximum allowable operating pressure reconfirmation must be based on the test factor required under § 192.619 or § 192.620, as applicable, for the installed date and class location at the time of installation.

(iii) *Pipeline Assessments.* Pipeline assessments must be conducted on the segment involved as follows:

(A) *Initial Assessment.* Within 24 months of the change in class location, the operator must identify each threat to which the segment involved is susceptible and conduct initial pipeline assessments for each threat.

***(1)* If the segment involved is covered by subpart O of this part, the operator must conduct initial pipeline assessments in accordance with §192.921.**

***(2)* If the segment involved is not covered by subpart O of this part, the operator must conduct initial pipeline assessments for applicable threats in accordance with §192.710.**

***(3)* An operator may use a prior assessment as an initial pipeline assessment for the segment if the prior assessment meets the requirements of §192.710 or §192.921, as applicable.**

***(4)* For the segment involved in the class location change, at a minimum, initial pipeline assessments must include:**

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

***(ii)* In-line inspection with either a high resolution geometry or a high resolution deformation tool, or an equivalent internal inspection device.**

(B) *Reassessments*.

***(1)* If the segment involved is covered by subpart O of this part, the operator must conduct reassessments in accordance with § 192.937.**

(2) **If the segment involved is not covered by subpart O of this part, the operator must conduct reassessments in accordance with § 192.710.**

(iv) ***Remediation*****. An operator must comply with § 192.711, § 192.713 or § 192.933, as applicable, to address conditions discovered through the integrity assessment program.**

(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 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 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 under paragraph (a)(4) of this section to restore the prior maximum allowable operating pressure** at a later date.

Respectfully submitted,
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