Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines; Proposed Rule

Docket No. PHMSA-2011-0023

Comments of The American Gas Association on the Safety of Gas Transmission and Gathering Pipelines Proposed Rule
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The American Gas Association (AGA), founded in 1918, represents more than 200 state regulated or municipal natural gas distribution companies. AGA members serve 95 percent of the 72 million natural gas customers, representing more than 160 million people in the United States who daily rely on natural gas service as a basic life necessity or use natural gas for business purposes. AGA and its members are committed to continuing to improve the high level of safety and the culture of safety compliance throughout the natural gas distribution industry. Numerous AGA programs and activities focus on the safe and efficient delivery of natural gas to customers. Safety is the number one priority of AGA members.

I. INTRODUCTION

AGA is deeply committed to continuing to improve natural gas pipeline safety and working collaboratively with PHMSA and other stakeholders to develop regulations and initiatives that provide meaningful advancements in pipeline safety. In the past, this constructive relationship has resulted in numerous regulatory developments that have made significant contributions to pipeline safety and have helped to achieve the excellent safety record of the nation’s natural gas pipeline system. AGA appreciates the opportunity to continue this relationship with PHMSA, and to provide constructive feedback and comments on PHMSA’s Safety of Gas Transmission and Gathering Pipelines Proposed Rule (Proposed Rule).¹

PHMSA describes the Proposed Rule as a response to multiple Congressional mandates from the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pipeline Safety Act), recommendations from the National Transportation Safety Board (NTSB), as well as addressing other aspects of natural gas pipeline operations that PHMSA has identified as requiring additional guidance. AGA recognizes the challenges associated with developing a comprehensive regulation that would address such a variety of topics and commends PHMSA on its effort. However, many of the topics within the Proposed Rule are not new but have been the source of significant discussion and debate among stakeholders in recent years. AGA recognizes and appreciates that many aspects of PHMSA’s Proposed Rule reflect these conversations and AGA’s positions, but is concerned that the overly prescriptive and onerous requirements result in a Proposed Rule that is largely unworkable and would significantly increase costs to residential customers and reduce the opportunities for operators to undertake ongoing federal and state regulatory mandated and voluntary initiatives targeted at advancing pipeline safety.

The Proposed Rule represents a shift away from performance-based regulations, which recognize the unique characteristics of each natural gas pipeline system, to prescriptive regulations, which define how an activity is to take place regardless of the circumstances or the characteristics of the system. AGA is concerned that in developing the Proposed Rule, PHMSA did not adequately consider the detrimental impact and effect on pipeline safety that imposing such prescriptive regulations may have. The unintended impact to natural gas distribution pipelines is the perfect example. Not only is the Proposed Rule directly impacting distribution pipelines through onerous new recordkeeping requirements and revisions to operational practices, but the magnitude and prescriptiveness of the Proposed Rule will have significant indirect impacts as well. Furthermore, operators with both transmission and distribution pipelines will ultimately have to reassign a greater percentage of finite resources to their transmission pipelines and pull resources away from voluntary actions on distribution pipelines, such as accelerated pipeline replacement programs.

AGA continues to be supportive of the Congressional mandate in Section 23 of the Pipeline Safety Act requiring operators to perform a one-time verification of maximum allowable operating pressure (MAOP) records and requiring the testing of pipelines in high-risk areas to verify MAOP. In fact, in 2013 AGA offered PHMSA a proposal to respond to this mandate and a commitment to go beyond the mandate. PHMSA’s Proposed Rule does not incorporate the effective solutions previously provided by AGA. AGA is concerned with the approach that PHMSA has taken as it attempts to apply universal integrity management solutions to a multitude of unique operator system configurations. This approach imposes severe limitations and operational inefficiencies that will likely result in excessive costs and limited benefit to the public. PHMSA’s proposed approach to MAOP Verification does not focus on the pipelines of greatest risk and concern to Congress, but instead, require complicated and unreasonable verification methods on pipelines far beyond those identified by Congress. In addition, as a result of the convoluted regulatory text and an attempt to apply a one-size-fits-all solution to MAOP Verification, it appears that many pipelines will be required to rely upon a pressure test or pipeline replacement without any consideration of risk. This is inconsistent with the Congressional mandate, PHMSA’s description of the program, and PHMSA’s estimate of the impact.

As PHMSA acknowledges, many operators are expanding the application of integrity management principles outside of high consequence areas (HCAs). AGA supports the expansion of integrity management principles outside of HCAs, as demonstrated through AGA’s Commitment to Enhancing Safety. However, AGA is concerned that PHMSA’s proposed approach to expanding integrity management by introducing the concept of “Moderate Consequence Areas (MCAs),” will divert the focus from integrity management to the resource-intensive administrative task of identifying these areas. In the Preliminary Regulatory Impact Assessment (PRIA), “PHMSA assumed that the cost of identifying MCAs is negligible compared to the cost of assessments and did not quantify the cost to identify MCAs.” This is one example of an assumption that was made in the PRIA that must be corrected since operators will expend up to twenty-five percent of the baseline assessment costs to identify and maintain MCAs.

AGA supports the intended pipeline safety benefits that are driving PHMSA’s proposed revisions to the pipeline safety regulations. To this end, AGA has included in its comments, an alternative approach to the concepts within PHMSA’s proposed Material Verification, MAOP Verification and Pipeline Assessments Outside HCAs. This separate approach is meant to be considered separately from the balance of these comments which are dedicated to PHMSA’s proposal. AGA’s approach recognizes PHMSA’s concerns and provides tangible and workable actions that AGA members are committed to taking to address these concerns. AGA welcomes the opportunity to discuss this approach with PHMSA.

The safe and reliable operation of natural gas pipelines requires the consideration and balance of a multitude of competing factors, including the allocation of finite resources, continuity of service, and the cost ultimately borne by the natural gas customers. Congress recognized the competing considerations that must be managed to safely operate natural gas pipelines and required PHMSA to consider these factors in prescribing minimum safety standards. AGA does not agree that PHMSA has accurately accounted for or considered these factors, including the true impact or the potential benefits associated with the Proposed Rule.

PHMSA’s PRIA for the Proposed Rule consists of a significant overestimate of potential benefits and a significant underestimate of the true impact to operators. For example, despite the fact that PHMSA’s proposed
requirement to verify operating pressure is described as offering operators the flexibility to select one of several verification methods, the PRIA describes several of the methods as “extreme measures” that operators would not use and eliminates these measures from consideration. For the methods the PRIA does address, the impact estimates fail to include significant aspects of the method, such as requiring a prescriptive and detailed engineering critical analysis in conjunction with in-line technology, or the requirement to perform a hydrostatic pressure test. PHMSA’s estimate of the potential benefits is equally troubling. Of PHMSA’s estimated benefits, approximately $274 million results from the misapplication of existing regulations that PHMSA describes as “cost savings.” The majority of the remaining benefits are derived from an estimated average incident consequence driven solely by one catastrophic event that resulted in damages that far exceeded any other pipeline incident of record. The flaws associated with the PRIA are severely skewed and do not support the prescriptive and impractical requirements found in the Proposed Rule.

The enormity of the Proposed Rule cannot be understated. PHMSA’s proposal represents the most significant revision to the regulation of gas transmission and gathering pipelines since 1970 when PHMSA’s predecessor first developed minimum pipeline safety standards. In fact, PHMSA itself describes the Proposed Rule as a “comprehensive strategy” to improve gas transmission safety and reliability. AGA is concerned that by undertaking a rulemaking of this magnitude, PHMSA has in essence diminished the impact and the importance of each one of the topics within the Proposed Rule. Many of these topics on their own could be considered significant rulemakings. Instead of receiving the due and required attention through a dedicated comment period and possible workshops and webinar, they are merely components of the Proposed Rule.

If the enormity of the Proposed Rule cannot be understated, neither can the commitment level of the resources that have been devoted to analyzing it and providing PHMSA with the most meaningful substantive comments within the limited time allotted and in the absence of explanation or reasoned justification. Through topic-specific task groups, AGA sponsored workshops, and multiple topic-specific weekly calls, AGA worked with its members to review and evaluate the Proposed Rule and provide meaningful comments. The minimal or, in many areas, no descriptions and justification, inconsistent statements, and convoluted proposed regulatory modifications included within the Proposed Rule made this no easy task. The limited timeframe to provide comments increased the challenge of conducting a thorough analysis of the proposed regulation and to provide meaningful comments. AGA’s comments are the culmination of this effort and are intended to provide PHMSA with the feedback and suggestions necessary to develop the Proposed Rule into a regulation that will make a meaningful enhancement in pipeline safety.

II. SUMMARY OF AGA’S COMMENTS

AGA provides the following executive summary of its detailed comments for PHMSA’s convenience. This summary in no way replaces the detailed remarks that AGA has provided on nearly every element of PHMSA’s Proposed Rule.

In addition to the topic-specific comments, AGA has provided PHMSA with an alternative framework for consideration. AGA’s alternative is in response to the prescriptive and complex manner that PHMSA has proposed to address the topics of Material Verification, MAOP Verification, and Pipeline Assessments Outside of HCAs. AGA believes its approach is more direct, would be easier to enforce, and would focus resources on the highest risk
areas, as opposed to meeting prescriptive regulations that would divert resources towards other areas. Most importantly, AGA’s approach would achieve PHMSA’s purpose in a manner that would further advance pipeline safety.

AGA provides the following summaries of its topic specific comments in response to PHMSA’s Proposed Rule:

1. **PHMSA’s Authority & Congressional Mandates:** Congress has provided PHMSA with the authority to prescribe minimum safety standards for pipeline transportation and for pipeline facilities through general and specific delegations of authority. AGA believes that many aspects of the Proposed Rule stretch or exceed the bounds of PHMSA’s authority. For many of PHMSA’s proposed requirements related to record keeping, record retention, MAOP Verification, and Material Verification, PHMSA references Section 23 of the 2011 Pipeline Safety Act as the source of its authority. Where PHMSA’s Proposed Rule attempts to go beyond these specific Congressional mandates, PHMSA is acting inconsistently with Congress’ clear intent and outside of PHMSA’s statutory authority.

Section 23 does not provide PHMSA with the authority to retroactively require documentation of material properties, operating history, or MAOP determinations of existing pipelines. It does not require that operators verify material properties of existing pipelines and it does not require that MAOP is reconfirmed for pipelines other than those in Class 3 and Class 4 locations and Class 1 and Class 2 HCAs. Finally, Section 23 does not require the testing of existing pipelines other than those previously untested transmission pipelines located in HCAs and operating at a pressure greater than 30% SMYS.

2. **Retroactivity:** PHMSA’s proposal to extensively revise the existing Pipeline Safety Code fails to address how the proposed revisions would apply to existing pipelines. Although the Proposed Rule makes substantial additions and revisions to the operational and recordkeeping requirements throughout retroactive and non-retroactive subparts alike, PHMSA has not adequately acknowledged the applicability of the proposed revisions to existing pipelines in the regulatory text. AGA encourages PHMSA to recognize the limits of its authority, as Congress has expressly prohibited PHMSA from retroactively regulating the “design, installation, construction, initial inspection, or initial testing of existing pipelines.”

AGA suggests that where PHMSA has proposed recordkeeping requirements in retroactive subparts, PHMSA should revise the regulatory text to make clear that recordkeeping obligations would apply only to new or fully replaced pipelines and only to records of actions or events occurring after the effective date of any final rule. PHMSA can accomplish this by referencing the effective date of the rule in the applicable sections.

3. **Impacts to Distribution Pipelines:** PHMSA has described the Proposed Rule as relating solely to transmission and gathering pipelines.\(^2\) Despite these statements, the Proposed Rule would have a substantial impact on distribution pipelines, both directly through proposed revisions that would have an immediate impact on distribution pipelines, and indirectly through a re-allocation of resources away from voluntary programs, such

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\(^2\)81 Fed. Reg. 20724 (Because this proposed rule applies only to gas gathering and transmission lines, this document will not discuss natural gas distribution infrastructure and its associated issues.).
as accelerated pipe replacement for pipelines identified by utilities and state regulatory agencies as a high priority for replacement. It will be impossible for local distribution companies that operate intrastate transmission pipelines to meet all of the mandates in the Proposed Rule and continue voluntarily replacing distribution lines at an accelerated rate. The cost to customers will be too substantial. The impacts to distribution systems have not been acknowledged by PHMSA, nor has PHMSA provided the type of reasoned justification or explanation necessary to support regulations that impact distribution pipelines.

4. **Definition of Transmission Line & Distribution Center:** AGA strongly encourages PHMSA to postpone its proposal to revise the definition of Transmission line until it can be given appropriate consideration. The current definition of Transmission line has been essentially unchanged since its codification in 1970 with the enactment of the original pipeline safety regulations. Operators have relied on this definition and made significant investments and business decisions based on it. Any revision to the definition of Transmission line will have substantial and significant impacts for the industry. If PHMSA moves forward with revisions to the Transmission line definition, AGA encourages PHMSA to form a multi-stakeholder advisory group to address the second criterion of the definition of Transmission line. Until then, PHMSA should revert back to “operates at a hoop stress of 20 percent or more of SMYS” and consider adding another criterion to remove regulatory obstacles for actions that will improve pipeline safety. AGA appreciates PHMSA’s acknowledgement that Distribution center should be defined for regulatory certainty and consistency, and provides PHMSA with suggestions to improve the definition.

5. **General Record Requirements:** AGA has significant concerns with PHMSA’s proposal to dramatically increase the records required to document compliance with all of Part 192 and to impose stringent new standards to validate those records for pipelines currently in service. See proposed 49 C.F.R. §192.13(e). PHMSA has significantly misrepresented the scope and significance of its proposed recordkeeping requirement. This also represents a reversal of PHMSA’s current record retention policy and regulations with no substantive explanation or justification. For pipelines currently in existence, this change exceeds PHMSA’s Congressional authority. In regard to PHMSA’s proposal that all records under Part 192 be “reliable, traceable, verifiable, and complete,” AGA encourages PHMSA to strike the term “reliable” as applicable to records and proposes a definition for Traceable, verifiable, and complete for prospective records related to the MAOP for natural gas transmission pipelines. AGA’s proposed definition is based on PHMSA’s past statements explaining these terms.

6. **MAOP Determination:** AGA believes that the proposed changes to MAOP Determination require clarification. The new record retention requirements should explicitly state that they are only applicable to gas transmission pipelines, are not retroactive, and are only required for records pertinent to MAOP Determination. In addition, the proposed changes to MAOP Determination include a reference to MAOP Verification, resulting in circular references between the two sections. Therefore, AGA recommends that PHMSA removes the reference for MAOP Verification within the section on MAOP Determination.

7. **Material Verification:** AGA does not believe it is appropriate to require that operators document and verify material properties of existing pipelines, fittings, valves, flanges and components above and beyond what was required by the regulations in place at the time the pipeline was put into service. This is beyond PHMSA’s Congressional authority. If PHMSA proceeds with requiring a Material Verification process for pipelines in HCAs and Class 3 & 4 locations without adequate material property records, AGA strongly urges PHMSA to
limit the applicability of prescriptive and unreasonable requirements within §192.607, narrow the physical attributes to only those needed in MAOP determination and remaining strength calculations, provide performance-based thresholds for operator defined Material Verification plans, align the determined prescriptive requirements with current technological capabilities and methodologies, and allow for new technology solutions.

8. **MAOP Verification**: AGA continues to support a pipeline safety regulation requiring the one-time MAOP Verification for high-priority natural gas transmission pipelines through methods that provide regulatory certainty and are technically justified. Specifically, AGA maintains its support for MAOP Verification consistent with the 2011 Pipeline Safety Reauthorization. AGA offers PHMSA suggested changes in the applicability of the section and in the methods that an operator can use for MAOP Verification. AGA encourages PHMSA to recognize the necessity for straightforward and technically justifiable requirements under each of the MAOP Verification methods, rather than overly prescriptive requirements that have no corresponding benefit in enhancing safety. AGA believes its recommendations provide the same level of safety in a manner that is clear and simple for operators to implement. AGA maintains that pipelines with test records supporting at least a 1.25 MAOP pressure test have a valid MAOP. Where a pipeline has such a test record, the proposal to verify the MAOP through the design formula as prescribed in §192.619(a)(1) is duplicative and unnecessary for the purposes of validating an MAOP. Additionally, AGA believes the final rule needs to clearly reflect that applying a method under MAOP Verification requirements inherently resolves any potential gaps in compliance with the requirements for MAOP determination for that pipeline.

9. **Fracture Mechanics**: Fracture mechanics is an analysis that has a limited place in preventing pipeline failures in some (relatively unusual) applications. AGA recommends that the regulation not prescriptively require fracture mechanics calculations to be performed for a broad range of applications as proposed by PHMSA. The set of pipelines for which fracture mechanics requirements apply should be limited to those that are at greatest risk of cracking threats, specifically legacy pipe operating over 30% SMYS. Additionally, experts in fracture mechanics should be given the latitude to conduct analyses in ways appropriate for the situation. Fracture Mechanics is a highly complex and specialized field that may not always predict failure pressures accurately. PHMSA should acknowledge the complexity and impact of this new requirement within the PRIA.

10. **Moderate Consequence Areas**: AGA supports the expansion of integrity management principles beyond HCAs as outlined in AGA’s Commitment to Enhancing Safety. However, AGA believes the introduction of a new pipeline classification as currently proposed will result in a burdensome MCA identification process and significant additional recordkeeping requirements that will divert resources away from the true intent of improving pipeline safety. AGA encourages PHMSA to consider alternative language to the proposed Moderate Consequence Area and Occupied Site definitions that will provide operators with a more simplistic approach to identifying MCAs and allow operators to invest resources more effectively while enhancing public safety. AGA’s recommendation is a two method approach, similar to the approach used for HCAs. The first approach would utilize existing Class Locations and the second approach would require the identification of sites within the potential impact radius.

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AGA Commitment to Enhancing Safety. See Appendix B of these comments. AGA’s Commitment to Enhancing Safety is a voluntary effort of AGA’s membership to uniformly increase and implement safety related practices and processes. It is a living document which is continually reviewed and updated by the AGA board.
11. **Definition of “Able to Accommodate Inspection by Means of an Instrumented In-Line Inspection Tool”:** In the Proposed Rule, PHMSA has placed a qualifier on the transmission pipelines in MCAs that are subject to the new requirements for MAOP Verification and Pipeline Assessments Outside of HCAs. The qualifier limits application of the new MCA requirements to pipeline segments that “can accommodate inspection by means of instrumented inline inspection tools (i.e. ‘smart pigs.’)” For regulatory certainty and clarity, AGA believes it is necessary for PHMSA to introduce a new definition for this qualifier. This will remove uncertainty and inconsistency in determining which pipelines meet PHMSA’s qualifier, and therefore which transmission lines are subject to the requirements of MAOP Verification and Pipeline Assessments Outside of HCAs.

12. **Reliability Assessments Outside of HCAs (AGA’s Proposed Subpart Q):** AGA supports the intent behind PHMSA’s proposal and believes that it is feasible for operators to implement. To assist in full recognition of what is required when planning for pipeline assessments, a clear and concise set of requirements should be codified that minimizes regulatory uncertainty. AGA is proposing that PHMSA create a new subpart for the additional assessment requirements outside of HCAs, and the ancillary regulatory requirements that accompany those requirements, including the stabilization of manufacturing and construction defects. The new subpart will improve clarity for operators through the proposed requirements.

13. **Transmission Integrity Management Program Preventative & Mitigative Measures:** AGA is supportive of PHMSA’s attempt to provide some additional guidelines around the selection of Preventative & Mitigative Measures (P&M) but has concerns with the proposed changes. As written, the proposed language prescriptively requires operators to perform all of the listed P&M measures and does not indicate that this list is a suggestion for consideration based on threats. Some items in this list include Leak Detection Systems, and Automatic Shut-off Valves and Remote Control Valves, which PHMSA has indicated will be addressed in separate rulemakings. In addition, the requirement of conducting hydrostatic tests and tests to determine material mechanic and chemical properties are so closely linked to the proposed material and MAOP Verification requirements that AGA believes their inclusion will ultimately cause regulatory confusion and uncertainty. AGA offers recommendations to clarify the requirements for P&M measures. AGA believes these recommendations will aid in meeting PHMSA’s intent without making the requirements redundant, overly burdensome, and costly.

14. **Use of Direct Assessment for Pipeline Assessments:** The proposed regulatory language to limit the ability to use Direct Assessment (DA) for pipeline assessments, unless all other assessment methods have been determined as unfeasible or impractical, is unreasonable. DA is a proven assessment technique that works in addressing the threat of corrosion. In addition, DA is a predictive tool that identifies areas where corrosion could occur while other methods can only detect where corrosion has resulted in a measureable metal loss. AGA recommends that PHMSA strike the limiting text from both the assessment descriptions in Transmission Integrity Management and in the new requirements for assessments outside of HCAs.

15. **Transmission Integrity Management Program Risk Assessments & Models:** AGA supports interactive threat analysis and incorporation of the outcomes of the analysis into risk models. However, AGA believes that PHMSA’s proposed requirement to mandate data integration, verification, and validation of an expanded number of datasets would serve to dilute the progress that operators have made to advance risk assessments. The proposed rule would require operators to gather, verify, and validate the integrity of 48 sets and subsets of information. Additionally, the proposed changes do not include an implementation timeline as written, and
imply that operators would be required to implement quantitative or probabilistic risk models immediately upon the effective date of the final rule, without regard to the time, challenges, and costs of data collection and integration, or the time necessary to evaluate and implement the requirements in the final rule.

The proposal also assumes that all operators currently have Geographic Information Systems (GIS) and the ability to conduct spatial analysis of integrity threats. Creating and maintaining a GIS is not a regulatory requirement, nor is it expressly proposed to be required by the rule. Operators utilize the systems that are most effective for their operations to implement integrity management programs. Requiring a GIS of all operators, as inferred by this code change proposal, and requiring the prescriptive list of data in a geospatial format, is a tremendous and time-consuming burden. For operators without a GIS, and operators without the listed data in a geospatial format, it would dilute an operator’s advancements in pipeline safety as they focus their resources on obtaining the data and entering it into a GIS. This would entail a shift in the manner by which operators manage their risk models, from optimizing a methodology that was effective for their pipeline system to a methodology required by the regulation.

16. **Repair Criteria for Pipelines in HCAs and Outside HCAs**: AGA understands PHMSA’s desire to update repair criteria for assessments within HCAs and supports clarity for repair criteria for assessments outside of HCAs. However, there are specific conditions for which AGA believes PHMSA’s justification for the repair timeline is lacking as industry research supports alternative timelines. AGA also provides in its comments alternative wording for the repair condition, which AGA believes will aid in clarity. Without carefully worded repair criteria conditions, operators will be left with requirements that are a distraction from actual threats on the pipelines and are overly burdensome to implement.

17. **Spike Test**: AGA supports the concept of spike tests and agrees with the pressure requirements within the Proposed Rule. However, AGA fundamentally disagrees with PHMSA’s required duration for the “spike” of 30-minutes and suggests a duration of 10-minutes to align with current industry research. AGA also urges PHMSA to reconsider the specification of a hydrostatic pressure test for spike testing. PHMSA has provided no independent technical justification for requiring only hydrostatic pressure tests, instead of pneumatic pressure tests, which are safe to perform at the pressure levels PHMSA has required. AGA has significant concerns regarding the inability to remove all water from intrastate transmission pipelines following a hydrostatic pressure test due to valves, bends, offshoots and other obstacles.

18. **Definitions of Legacy Pipe & Legacy Construction Techniques**: AGA recognizes PHMSA’s desire to identify pipelines that may be susceptible to manufacturing- or construction-related defects as a result of now-abandoned materials and techniques. AGA supports this philosophy. As defined in the Proposed Rule, however, AGA is concerned that the definitions would unnecessarily subject pipelines without these concerns to the expanded regulatory requirements. AGA offers two potential solutions. First, AGA suggests replacing the single reference to these terms that is in the MAOP Verification requirements with the criteria that the definitions describe, thus eliminating the necessity of the definitions themselves. Otherwise, AGA suggests alternative language for both definitions to more accurately encompass PHMSA’s concerns.

19. **49 C.F.R. Part 192 Proposed Appendix A - Record Retention Schedule**: AGA strongly disagrees with PHMSA’s statement that Appendix A functions to “more clearly articulate” the requirements for records preparation
and retention for transmission pipelines. Appendix A introduces entirely new record keeping obligations by including retention requirements and/or retention times for records that are not required by existing or proposed regulatory text. In addition, several of the retention requirements found in Appendix A would apply solely to distribution facilities, which is outside of PHMSA’s stated scope of the rulemaking. Any differences between the regulatory text and Appendix A will result in regulatory uncertainty, and will detract from PHMSA’s and operators’ ultimate goals of advancing pipeline safety. PHMSA’s introduction of new record requirements through Appendix A is misleading and inappropriate. AGA strongly encourages PHMSA to eliminate Appendix A in its entirety from the final rule.

20. Prospective Material, Design, & Construction Records: PHMSA’s proposal to add material, design and construction record requirements expressly acknowledges that the current pipeline safety code does not require an operator to maintain these particular records nor any other records not specifically called out in regulations or the operator’s procedures. In addition, AGA is concerned that the phrase “acquire and retain” and “make and retain” would imply that the obligation to maintain these records is a retroactive requirement. This exceeds PHMSA’s Congressional authority. Finally, the regulation should make clear that the “transmission pipeline” is the subject of the regulation, not the “operator of the transmission pipelines” as stated in the Proposed Rule.

21. Management of Change: AGA supports the concept of Management of Change (MoC) as it applies to transmission integrity management and control room centers. However, PHMSA has significantly underestimated the impact and burden of its current proposal, which would dramatically expand the scope of the types of changes to be included as well as the pipelines to which it would apply. Under the existing code, MoC is applicable only to transmission pipelines in HCAs, whereas proposed code implies distribution pipelines to be included in MoC. AGA does not support PHMSA’s application of MoC to all pipelines and processes, which would result from PHMSA’s proposal to move MoC requirements from 49 C.F.R Part 192 Subpart O-Gas Transmission Integrity Management to Subpart A-General. AGA supports operators voluntarily adopting the American Petroleum Institute’s (API) Recommended Practice 1173: Pipeline Safety Management Systems (API RP 1173; PSMS), which includes MoC elements.

22. 49 C.F.R. Part 192 Subpart I – Requirements for Corrosion Control: AGA agrees that existing requirements have been influential in protecting pipelines from corrosion damage. While PHMSA’s proposals were made with the intent of improving pipeline integrity, and AGA is supportive of that goal, there are proposed Subpart I changes that are unnecessarily burdensome, costly to operators as presented, and do not contribute effectively to pipeline safety. AGA’s comments recommend modifications on sections that address post construction or assessment dig coating surveys, external corrosion control monitoring, the monitoring and mitigation of internal corrosion, and corrosion remedial measures for transmission pipelines.

23. Requirements for Internal Corrosion Direct Assessment & Stress Corrosion Cracking Direct Assessment: AGA does not support the incorporation by reference, nor the required application, of standards that are not widely used and adopted by natural gas pipeline operators. Additionally, the proposed regulation goes beyond international standards without providing the intended protections to improve internal corrosion assessments. AGA opposes PHMSA’s general conclusion that the strict incorporation of these standards would
have negligible impact. AGA proposes that PHMSA maintain references to existing standards and allow for incorporation of new standards. AGA believes this approach meets PHMSA’s intent to improve pipeline safety in a manner that is reasonable and effective.

24. **49 C.F.R. Part 192 Appendix D – Criteria for Cathodic Protection and Determination Measurements**: PHMSA is proposing to modify Appendix D to Part 192. AGA does not support these changes as they are unsubstantiated, reflect earlier industry knowledge and standards, and are unnecessary. In addition, while PHMSA asserts that the changes would only apply to gas transmission and gathering lines, the changes to Appendix D would also impact distribution since Appendix D currently applies to gas distribution systems. AGA encourages PHMSA to maintain the existing Appendix D language with only minor revisions to terminology.

25. **Continuing Surveillance after Extreme Weather Events**: AGA agrees that it is prudent for operators to perform patrols of at-risk pipelines and facilities following an extreme weather event when the operator has reason to believe there is a reasonable likelihood that the extreme weather event may have affected its system. However, AGA believes that the proposal is duplicative to existing regulations and AGA is concerned that the broad applicability of the proposal, coupled with the prescriptive inspection requirements, would require the inspection of pipelines during times when personnel is focused on emergency response, exposed to greater safety risks related or unrelated to its system, and could require numerous unnecessary inspections. AGA is also concerned that the proposed language could be interpreted as requiring physical excavation and inspection of the pipeline, or the undertaking an in-line inspection, following an extreme weather event. AGA encourages PHMSA to recognize the duplicative nature of this proposal, and, at a minimum, revise the proposed requirements to provide operators with a greater level of discretion in determining when actions are needed following an extreme weather event.

26. **Gathering Lines**: AGA generally supports the comments submitted by API, the Independent Petroleum Association of America (IPAA), the Gas Processors Association (GPA) and the Texas Pipeline Association (TPA) on gas gathering pipelines. AGA believes further consideration by PHMSA is necessary before the new definitions, added classifications, and expanded requirements are incorporated into the Final Rule. Furthermore, AGA has serious concerns about PHMSA’s estimate of impact for gas gathering lines. AGA understands this is largely due to discrepancies between the proposed regulatory text and PHMSA’s intent for gas gathering lines. However, this confusion should not and cannot continue when the Final Rule is published.

27. **49 C.F.R. Part 192 Incorporations by Reference**: AGA does not support PHMSA’s proposal to incorporate by reference “recommendations” found within industry consensus standards. PHMSA has failed to provide justification for these inclusions or for its departure of limiting the portions of consensus standards incorporated by reference to those portions that include “requirements.” Consensus standards are written and approved by the members of the consensus organization and include a public review for standards which follow the ANSI standard approval process. In developing these standards, purposeful thought is provided on which obligations should be recommended and which required. PHMSA’s proposal to mandate “recommendations” contained in the proposed IBR documents should be deleted.

28. **Preliminary Regulatory Impact Assessment**: AGA has identified many errors and inconsistencies in PHMSA’s PRIA methodology and assumptions, and discrepancies between the Proposed Rule and the PRIA. In addition,
many of the PRIA cost estimates severely underestimate actual costs experienced by operators. The lack of reasonable cost estimates impedes reviewers’ opportunities to comment on the Proposed Rule and its impacts. Without accurately accounting for the costs associated with this proposed regulation, even the portions supported by industry, the Office of Management and Budget, and thus the public, will never be able to truly understand the economic impact of this rulemaking until it is too late and the heavy burdens of cost are borne by the public with much less benefit than predicted by PHMSA. The significant and widespread inaccuracies result in a PRIA that clearly fails to meet Congressional requirements and exceeds PHMSA’s general authority.

29. **Environmental Impact Assessment**: AGA believes the Environmental Impact Assessment for the Proposed Rule fails to consider several areas that would have direct environmental impacts and consequences. PHMSA has underestimated the scope of excavations required by the Proposed Rule and failed to consider the significant amount of waste, both water and soil, that would be generated as a direct result of the increased testing and inspection requirements found in the Proposed Rule. It has also failed to consider the greenhouse gas emissions that will result from the purging of lines prior to hydrostatic testing and when lines need to be removed from service for repair or replacement. Because PHMSA has provided no supporting documentation on how the values in the Environmental Impact Assessment were calculated, stakeholders can provide no meaningful or substantive comments on the values that were used.

AGA also requests that PHMSA acknowledges the number of regulatory initiatives addressed when considering the effective date of the final rule. Given the enormity of the Proposed Rule, AGA believes that the industry would need a minimum of one year to begin implementation of the changes.

In the detailed, topic-specific comments that follow, AGA has identified those aspects of the Proposed Rule that AGA supports, and those areas where AGA disagrees with PHMSA. In each section, AGA has attempted to provide PHMSA with an alternative approach. AGA’s edits are provided onto the pipeline safety code as it would appear if AGA’s proposed edits were incorporated. AGA’s suggested edits are highlighted in red font. In some cases, AGA has reintroduced current regulatory text that was removed by PHMSA in the Proposed Rule. This reintroduced text is also highlighted in red. If PHMSA has any questions about AGA’s alternative proposals, AGA encourages PHMSA to contact us for clarifications.

**III. GENERAL COMMENTS**

**A. PHMSA Authority & Congressional Mandates**

**PHMSA’s Authority to Promulgate Minimum Safety Standards**

Congress has provided PHMSA with the authority to prescribe minimum safety standards for pipeline transportation and for pipeline facilities through general and specific delegations of authority. AGA believes that
many aspects of the Proposed Rule stretch or exceed the bounds of PHMSA’s authority and AGA finds it appropriate to provide this general discussion.

Section 23 of the 2011 Pipeline Safety Act

Section 23 of the Pipeline Safety Act, 49 U.S.C. §60139, mandated specific actions to be taken by the Secretary of Transportation, through PHMSA, regarding the verification of existing records, reconfirming MAOP, and testing of previously untested natural gas transmission pipelines in limited circumstances. These actions were to be taken on specific locations and operating stress levels of transmission pipelines – that is, those pipelines that Congress deemed to be of highest priority – as well as in consideration of public safety, service disruptions, and cost. Further, PHMSA failed to adequately consider or sufficiently take into account the financial burden of creating new record requirements on pre-existing natural gas pipelines and the costs of creating records sufficient to meet the proposed new requirements.

For many of PHMSA’s proposed requirements related to record keeping, record retention, MAOP Verification, and Material Verification, PHMSA references Section 23 of the 2011 Pipeline Safety Act as the source of its authority. AGA finds it appropriate to remind PHMSA of the limited and discrete actions that were addressed by Section 23. Where PHMSA’s Proposed Rule attempts to go beyond these specific Congressional mandates, PHMSA is acting inconsistently with Congress’ clear intent and PHMSA’s statutory authority.

Section 23 required that operators of transmission pipelines in Class 3 and 4 locations and Class 1 and 2 HCAs “verify” their records to ensure that records accurately reflect the physical and operational characteristics of the pipelines and to confirm the established MAOP. See 49 U.S.C. §60139(a). Operators were required to report to PHMSA those pipeline segments for which the records were insufficient to confirm the established MAOP. Id. at §60139(b)(1). In response to these Congressional mandates, PHMSA issued two Advisory Bulletins, ADB 11-01 and ADB-2012-06, regarding the verification of records establishing MAOP, for natural gas transmission pipelines, and MOP, for hazardous liquid pipelines.

As directed in the Act, PHMSA will require each owner or operator of a gas transmission pipeline and associated facilities to verify that their records confirm MAOP of their pipelines within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in HCAs.

PHMSA intends to require gas pipeline operators to submit data regarding mileage of pipelines with verifiable records and mileage of pipelines without records in the annual reporting cycle for 2013.

See 77 Fed. Reg. 26822. Since that time, operators have been evaluating their records and have reported to PHMSA the mileage of pipelines within Class 3 and Class 4 locations and in Class 1 and Class 2 HCAs with records insufficient to confirm the established MAOP. These actions satisfy the Section 23 Congressional mandates related to records verification.

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The Congressional mandates in Section 23 to reconfirm MAOP and require testing of previously untested natural gas transmission pipelines in HCAs that operate at a pressure greater than 30% Specified Minimum Yield Strength (SMYS) were imposed with explicit instructions to PHMSA to focus on those pipelines at highest risk and to take into account the myriad of factors influencing operation of pipelines. Specifically, for those natural gas transmission pipelines in Class 3 and Class 4 locations and Class 1 and Class 2 HCAs that operators identified as having records insufficient to confirm the established MAOP, Section 23 requires that operators reconfirm the MAOP as “expeditiously as economically feasible.” See 49 U.S.C. §60139(c). For those previously untested pipelines, PHMSA was instructed to develop regulations for operators to confirm the material strength of previously untested natural gas transmission pipelines located in HCAs and operating at a pressure greater than 30% SMYS. Id. at §60139(d). These regulations required the consideration of testing methodologies including pressure testing and in-line inspections, and other alternatives determined to be of equal or greater effectiveness. In addition, Section 23 also requires PHMSA to consult with the Federal Energy Regulatory Commission (FERC) and State regulators to establish timeframes for the completion of such testing that takes into account public safety and the environment and that minimize costs and service disruptions.

It is important to note that Section 23 does not:

- Provide PHMSA with the authority to retroactively require documentation of material properties, operational history, or MAOP determinations of existing pipelines.
- Require that operators verify material properties of existing pipelines.
- Require that MAOP is reconfirmed for pipelines other than those in Class 3 and Class 4 locations and Class 1 and Class 2 HCAs.
- Require testing of existing pipelines other than those previously untested transmission pipelines located in HCAs and operating at a pressure greater than 30% SMYS.

To the extent that PHMSA’s Proposed Rule is inconsistent with these Congressional mandates, they exceed PHMSA’s statutory authority.

Section 5 of the 2011 Pipeline Safety Act

Section 5 of the 2011 Pipeline Safety Act required the Secretary of Transportation, through PHMSA, to evaluate whether gas transmission integrity management program requirements, or elements thereof, should be expanded beyond HCAs and whether applying integrity management program requirements to additional areas would mitigate the need for class location requirements. See Pub. L. No. 112-90. As part of this evaluation, PHMSA was required to include its findings in a report to Congress. Within Section 5, Congress expressed its clear intent to be able to review the report before PHMSA initiated any rulemakings. This report was not provided to Congress in the timeframe mandated by the 2011 Act. In addition, the report was only provided to the public on June 9, 2016, two days after the comment period on the Proposed Rule was initially scheduled to close. Congress provided PHMSA with clear direction on how to proceed in its evaluation and, if necessary, how to proceed with requiring the expansion of natural gas transmission integrity management requirements, or elements thereof, beyond HCAs. PHMSA has not complied with this mandate. PHMSA’s non-compliance has also eliminated a congressionally-mandated process requirement that would have provided Congress and the public notice and a reasoned explanation of its decision-making process. These requirements remain unfulfilled, which is a denial of notice and process under the Pipeline Safety Act and the Administrative Procedures Act.
Responding to NTSB Recommendations

PHMSA describes the Proposed Rule as addressing several pending NTSB recommendations. AGA’s comments on specific NTSB recommendations are addressed in the detailed comments that follow. In addition, AGA believes it appropriate to identify the considerations that PHMSA must take into account when responding to an NTSB recommendation. Further, PHMSA may not delegate its regulatory authority and must provide its own independent reasoning and justification for any NTSB recommendations it may adopt, none of which have been provided.

AGA has the upmost respect for the NTSB and its investigative expertise. Post-incident recommendations usually address a specific issue uncovered during an individual investigation or study and specify how to correct that specific situation to help minimize the chance of reoccurrence. Because recommendations are specific to a unique event, pipeline or operator, the recommendations themselves, along with their reasoning and justification, may not be operationally, technically, or economically feasible and generally cannot and should not be adopted verbatim as regulatory language, which typically applies to all natural gas pipelines and operators. Consistent with this distinction, the NTSB has stated that it is not its role to write regulations or determine how to operate pipelines. The NTSB also has stated it is open to alternative approaches in response to its recommendations and has recognized that its recommendations are not subject to cost-benefit analyses, as PHMSA’s regulations are.

In general, AGA believes that there are more effective regulatory alternatives than adopting the NTSB recommendations verbatim. Notwithstanding an NTSB recommendation, PHMSA may not address an NTSB recommendation unless it has the authority to do so. As discussed in more detail below, PHMSA’s authority is not all encompassing and is limited to PHMSA’s reasoned consideration of a multitude of factors, including practicability, reasonableness, appropriateness, and cost. If there were reasoned consideration of these factors by PHMSA, they have not been disclosed.

PHMSA’s General Authority

Congress has provided PHMSA with the authority to prescribe minimum safety standards for pipeline transportation and for pipeline facilities. These standards are to be practicable and designed to meet the need for natural gas pipeline safety. See 49 U.S.C. §60102(b). Recognizing the competing considerations that must be managed to safely operate natural gas pipelines, Congress identified specific factors PHMSA must take into account when issuing a standard. Specifically, for natural gas pipelines, PHMSA must consider relevant available safety and environmental information, the appropriateness of the standard for the particular type of pipeline, the reasonableness of the standard, and the reasonably identifiable or estimated benefits and costs. A standard may only be issued upon a reasoned determination that the benefits of the intended standard justify its costs. Id. at 60102(b)(5). PHMSA is expressly prohibited from regulating the design, installation, construction, initial inspection, or initial testing of existing pipelines. Id. at §60104(b). Finally, if “continuity of gas service” is affected, PHMSA must consult with FERC and the states. Id. at §60104(d).

AGA finds it appropriate to remind PHMSA of the limitations on its authority and its process obligations in connection with the Proposed Rule. As detailed in AGA’s comments, the Proposed Rule is excessively prescriptive, would have impacts outside of transmission and gathering lines, and in many instances would be impracticable for transmission pipeline operators, and especially intrastate transmission pipeline operators, to comply with. In support of these proposed requirements, PHMSA has provided very little in terms of justification, support, or even descriptions. PHMSA’s lack of justification or details hinders stakeholders’ ability to adequately
assess the impact and provide meaningful comment to PHMSA. With many of PHMSA’s newly proposed regulatory requirements, including MAOP Verification and Material Verification, the proposed regulatory text has created gaps, duplications, and inconsistencies in the regulation. Where this occurs, PHMSA’s lack of a detailed description or justification provides stakeholders with no guidance on PHMSA’s intent and stakeholders are left trying to sort out regulatory conundrums.

PHMSA’s PRIA further complicates matters. The PRIA fails to account for numerous, significant costs such as retroactively documenting material properties and compliance with Part 192 and methodologies for verifying MAOP. In addition, there are many instances where the descriptions of proposed regulatory requirements and impact estimates are inconsistent with the proposed regulatory text. As a result of the inconsistencies and errors in the PRIA, stakeholders are hindered in providing meaningful comment and it cannot be said that PHMSA has met its statutory obligation to consider costs and benefits.

Finally, despite the significant impact the Proposed Rule would have on natural gas pipeline operators, including coordination of resources for additional assessments, inspections, and testing, and the impacts these assessments could have on the continued reliability of service, there is no record in the regulatory docket documenting PHMSA’s coordination with FERC or the states to ensure continuity of gas service and to limit service disruptions.

It is for these reasons that AGA believes that many aspects of the Proposed Rule stretch or exceed the bounds of PHMSA’s authority as granted by Congress.

B. Retroactivity of PHMSA’s Proposed Rule

**PHMSA Should Clearly State the Prospective and Limited Retroactive Effect of the Proposed Rule**

PHMSA’s proposal to extensively revise the existing Pipeline Safety Code fails to address how the proposed revisions would apply to existing pipelines. In addition, PHMSA has proposed changes that legally should not apply to existing pipelines. As a result of this silence and PHMSA’s lack of authority to promulgate certain retroactive requirements on existing pipelines, there is considerable ambiguity and regulatory uncertainty as to the applicability of many of the proposed operational and recordkeeping requirements on existing pipelines. AGA encourages PHMSA to recognize the limits of its authority in regulating existing pipelines as related to the subject of retroactivity and to revise its proposed rule so that the regulatory text clearly states the applicability of each code section on new and existing pipelines.

A rule is considered retroactive if it creates a new obligation or imposes a new duty to past actions. Absent specific Congressional authority, agencies lack the authority to promulgate retroactive regulations. Not only has Congress not explicitly provided PHMSA with this authority, Congress has expressly prohibited PHMSA from retroactively regulating the “design, installation, construction, initial inspection, or initial testing” of existing pipelines. See 49 U.S.C. § 60104(b). When promulgating the initial Pipeline Safety Code, the Department of

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5 Nat’l Mining Ass’n v. Dep’t of Labor, 292 F.3d 849, 859 (D.C. Cir. 2002).
6 Georgetown Univ. Hosp. v. Bowen, 488 U.S.204, 208 (1987) (“[r]etroactivity is not favored in the law;” “a statutory grant of legislative rulemaking authority will not, as a general matter, be understood to encompass the power to promulgate retroactive rules unless that power is conveyed by Congress in express terms.”)
Transportation expressly noted its limited authority in response to concerns regarding the effect of the new regulations on existing pipelines. According to PHMSA’s predecessor, the Hazardous Materials Regulations Board, in addressing the application of new regulations on existing pipelines, “there [was] no basis for this concern.” See 35 Fed. Reg. 13248, 13250 (Aug. 19, 1970). The Hazardous Materials Regulations Board went on to describe §192.13 as “clearly stating the applicability of these regulations to new and existing pipelines, and to avoid confusion as to the retroactive effect of these standards.” Id. at 13251.

49 C.F.R. §192.13 serves as the guidepost for establishing which subparts of the Pipeline Safety Code new pipeline safety regulations can retroactively apply to existing pipelines and which subparts new pipeline safety regulations cannot. It is understood that new regulations can retroactively apply to the following subparts of the Pipeline Safety Code, that is, these sections are “retroactive”:

- Subpart A—General
- Subpart I—Requirements for Corrosion Control
- Subpart K—Uprating
- Subpart L—Operations
- Subpart M—Maintenance
- Subpart O—Gas Transmission Pipeline Integrity Management
- Subpart P—Gas Distribution Pipeline Integrity Management

The remaining subparts of the Pipeline Safety Code are not considered retroactive and are not applicable to existing pipelines. Although subparts A, I, K, L, M, O and P of the Pipeline Safety Code are generally considered “retroactive,” any regulation within these subparts that touches on the “design, installation, construction, initial inspection, or initial testing” is not considered retroactive consistent with Congress’ limitation on PHMSA’s authority to regulate existing pipelines.

Although the Proposed Rule makes substantial additions and revisions to the operational and recordkeeping requirements throughout retroactive and non-retroactive subparts alike, PHMSA has not adequately acknowledged the applicability of the proposed revisions to existing pipelines in the regulatory text. The result is that PHMSA has failed to propose regulations that would provide operators or regulators with regulatory certainty of their effect and applicability on both existing pipelines and prior compliant actions.

To address these concerns, AGA suggests that PHMSA make the following revisions:

- **Recordkeeping Requirements in Retroactive Subparts**: Where PHMSA has proposed recordkeeping requirements in retroactive subparts, PHMSA should revise the regulatory text to make clear that recordkeeping obligations would apply only to new or fully replaced pipelines. PHMSA is prohibited from retroactively applying design, construction, initial inspection, and initial testing requirements to existing pipelines when a new regulation is adopted. That prohibition applies equally to recordkeeping requirements, including new recordkeeping obligations related to construction and design that were

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7 Although Subpart I today is considered retroactive, at one time this subpart was not considered to be generally retroactive. In response to concerns regarding the applicability of new corrosion control requirements to existing pipelines, the Department of Transportation noted its lack of authority to regulate existing pipelines and expressly noted in the code those operational and maintenance provisions that would be applicable to existing pipelines. See 36 Fed. Reg. 12297, 297-298 (June 30, 1971).
never required to be maintained by the code for existing pipelines. By retroactively imposing new record requirements and by raising the standard of quality applied to records, PHMSA is impermissibly altering the past legal consequences of past actions. PHMSA has no authority to impose the recordkeeping requirements proposed in §192.13(e) and §192.619(f) retroactively and should revise these sections to make clear that the recordkeeping obligation applies to records of actions or events occurring after the effective date of any final rule.

• **Recordkeeping Requirements in Non-Retroactive Subparts**: PHMSA has proposed several new recordkeeping requirements and retention times in non-retroactive subparts. AGA is concerned that with the passage of time, it will be unclear as to which pipelines these requirements apply and regulators will expect this documentation for pipelines that were already in existence at the time the standard was implemented. To alleviate this confusion, where PHMSA has proposed recordkeeping requirements in non-retroactive subparts, PHMSA should revise the regulatory text to make clear that recordkeeping obligations apply only to records of actions or events occurring after the effective date of any final rule. This would apply to the recordkeeping requirements proposed in §192.67, 192.127, 192.205, 192.227, 192.285, and 192.319.

• **Operational Requirements in Retroactive Subparts**: Through the Proposed Rule, PHMSA has proposed to impose stringent and prescriptive operational requirements on natural gas transmission, and sometimes distribution, pipelines. By proposing extensive revisions to operational requirements in retroactive subparts of the code and not acknowledging the potential retroactivity, the proposed regulations are ambiguous as to their effect on existing pipelines and timing for compliance. For example, PHMSA has proposed revisions to internal and external corrosion control requirements. Because this is in a retroactive subpart of the Pipeline Safety Code, these requirements will apply to existing pipelines. AGA is concerned that as drafted, a regulator could apply these regulatory provisions to past compliant actions and could question whether these past actions were conducted in compliance with the revised code. To alleviate this ambiguity, PHMSA should revise these sections to make their applicability clear by referencing the effective date of any final rule.

• **Operational Requirements in Non-Retroactive Parts**: PHMSA also has proposed revising operational requirements in non-retroactive subparts of the Pipeline Safety Code. To eliminate confusion as to when these requirements came into effect and thus, which pipelines they apply to, AGA suggests that PHMSA references the effective date of any final rule in these sections.

In clarifying the retroactive and prospective application of PHMSA’s proposed revisions, AGA reminds PHMSA of its limited authority in regulating existing pipelines and the general presumption that regulations have prospective effect.

**C. Impacts to Distribution Pipelines**

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8 *Georgetown*, 488 U.S. at 216 (Scalia, J., concurring).
PHMSA has described the Proposed Rule as relating solely to transmission and gathering pipelines. Despite these statements, the Proposed Rule would have a substantial impact on distribution pipelines, both directly through proposed revisions that would have an immediate impact on distribution pipelines, and indirectly through a re-allocation of resources away from voluntary programs, such as accelerated pipe replacement programs for those pipes identified by utilities and state regulatory agencies as being the highest priority for replacement.

The indirect impact to distribution pipelines is due to the magnitude and prescriptiveness of the Proposed Rule, both which would require local distribution companies with intrastate transmission and distribution assets to reassign their limited resources to their transmission assets and away from their distribution assets. Local distribution companies must comply with federal and state regulatory requirements before placing resources toward voluntary actions, such as faster replacement of cast iron, bare steel and historic plastic pipe, and other voluntary actions such as those that reduce excavation damage, emergency response training with local emergency responders, efforts to create or enhance the company’s geographic information system, and research and development. Local distribution companies will need to seek approval from state utility commissions to continue their current pace of distribution replacement and other voluntary efforts, and the state commissioners will need to balance the cost of regulatory compliance and voluntary initiatives with the impact on customer rates. Since natural gas customers bear the cost of federal and state regulatory compliance, state commissioners will only be able to lessen the impact on customers by reducing a company’s voluntary actions.

Nowhere in the Proposed Rule or the PRIA does PHMSA address or even acknowledge the substantial direct impact the Proposed Rule would have on distribution systems. Given this lack of consideration or justification for regulating and impacting distribution systems, PHMSA must recognize that the final rule cannot regulate distribution pipelines and will need to be revised so that impacts, direct or indirect, to distribution pipelines are explicitly eliminated.

In fact, during the PHMSA Public Webinar on June 8, 2016, pertaining to this rulemaking, PHMSA made repeated statements that the Proposed Rule has no impacts on distribution pipelines, that it was intended to apply solely to gas transmission and gathering lines, and that any impact to distribution pipelines was unintended. AGA appreciates PHMSA’s comments that the Proposed Rule was not intended to apply to distribution pipelines, but disagrees that there are no impacts on distribution. AGA provides PHMSA with comments in this section and elsewhere in the comments detailing the direct and indirect impacts the Proposed Rule would have on distribution systems.

Parts 191 and 192 of the Pipeline Safety Code contain regulatory requirements that apply to distribution pipelines. Part 191 applies to pipelines generally, defining “pipeline” and “pipeline system” without distinction between transmission, gathering, and distribution pipelines. See 49 C.F.R. §191.3. Within Part 192, “distribution line” is defined as a pipeline that is not a gathering or transmission pipeline. Id. at §192.3. The Proposed Rule would revise Parts 191 and 192 in ways that would have a direct impact on distribution pipelines.

As PHMSA is aware, it is a well-established fact that gas distribution pipelines behave in significantly different ways from gas transmission pipelines. Typically, distribution pipelines have smaller diameters and

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981 Fed. Reg. 20724 (Because this proposed rule applies only to gas gathering and transmission lines, this document will not discuss natural gas distribution infrastructure and its associated issues.).
operate at lower pressures and at lower hoop stress levels than transmission pipelines. Distribution pipeline failures are more likely to involve slow leaks with limited volume because the internal gas pressure is much lower than for transmission pipelines. The general risk for distribution pipeline gas releases is from accumulation and migration of gas, not the immediate release of large volumes of gas that is typical of failures with transmission pipelines. PHMSA’s Proposed Rule fails to consider or even acknowledge the significant impacts to distribution and fails to take into account these significant differences between distribution pipelines and transmission pipelines. There is simply no justification or reasoned analysis supporting a determination that the proposed regulations for transmission pipelines are also appropriate for distribution pipelines.

The following are areas in the Proposed Rule that AGA has identified as impacting distribution pipelines and systems. These impacts, as well as suggested revisions to the code, are addressed in the topic-specific comment sections.

PHMSA has proposed to revise the definition of “transmission line.” See 81 FR 20826. Because “distribution line” is defined in terms of what is not a “transmission line,” any revision to the definition of transmission line that will impact the number of miles of transmission line will necessarily have an impact on the number of miles of distribution pipelines (i.e., definitional changes that increase the number of miles of transmission line essentially do so by converting distribution or gathering lines into transmission lines). As described elsewhere in these comments, the proposed revision to the “transmission line” definition will greatly impact the number of miles that are classified as transmission lines and will have repercussions beyond this rulemaking since the number of transmission miles as reported to PHMSA is used by other regulatory programs. If finalized, the revised definition would require operators to evaluate their pipeline systems to determine the pipelines that have been impacted by the revised definition and determine how to manage that pipeline under the revised classification. AGA’s comments separately address PHMSA’s proposed definition of “transmission line,” but notes here that PHMSA has not acknowledged the impact that its proposed change to the definition of a transmission line would have on distribution lines and other federal agency programs.

PHMSA has proposed extensive new record keeping requirements that would apply to distribution pipelines, both existing and new. PHMSA’s proposed §192.13(e) and §192.619(f) would impose new retroactive record keeping requirements. Neither of these sections are limited to transmission pipelines and thus would apply directly to distribution pipelines, without any stated justification or acknowledgement by PHMSA. In addition, PHMSA’s proposed Appendix A is purporting to “clarify” record keeping requirements for transmission pipelines, yet Appendix A includes references to code sections that also apply to distribution pipelines and it adds new record keeping requirements not found elsewhere in Part 192. This is not a clarification, but a substantive change in the requirements for both transmission and distribution pipelines. For example, proposed Appendix A includes §192.305, which requires inspections for transmission lines and distribution mains, but contains no record keeping requirements.

As addressed elsewhere in these comments, AGA does not believe that PHMSA has the legal authority to impose retroactive recordkeeping requirements and new recordkeeping requirements through Appendix A. More so, AGA is particularly concerned that PHMSA has proposed changes to the pipeline safety regulation that have a significant impact on distribution pipelines, without explanation or acknowledgement. In addition, PHMSA provides no justification or rational basis for requiring distribution pipelines to document operational activities to the same level as transmission pipelines. Distribution pipelines operate at lower pressures and stress levels than
transmission pipelines and generally present less risk than higher pressure, higher stress transmission pipelines. Any revision to the recordkeeping requirements for distribution should be done through a separate rulemaking. AGA urges PHMSA to make revisions to these proposals to expressly exclude distribution pipelines from the final rule and to take into account AGA’s other concerns and recommendations regarding the proposed recordkeeping requirements made elsewhere in these comments.

Through the Proposed Rule, PHMSA has created a new Material Verification requirement that, on its face, would apply to certain categories of transmission pipelines if the pipeline does not have what PHMSA believes to be adequate material records. See Proposed §192.607. Although the text of proposed §192.607 applies only to a subset of transmission pipelines, PHMSA is proposing to add references to §192.607 throughout Part 192 that could be interpreted to expand the Material Verification requirements found in proposed §192.607 to distribution pipelines. For example, proposed §192.13(e)(3) would require transmission and distribution pipelines without documentation to comply with proposed §192.607. There is no justification provided within the Proposed Rule to apply Material Verification requirements on distribution systems. AGA believes these records are unnecessary to operate a distribution system safely due to the significantly lower pressure and stress levels that distribution systems operate at and the fact that operators were not required to maintain the material records that PHMSA now seeks to require. AGA has significant concerns with PHMSA’s proposed Material Verification requirements generally, but notes here that these requirements, as proposed, would have a significant impact on distribution systems – impacts that are not addressed or acknowledged by PHMSA within the Proposed Rule. Again, AGA requests that PHMSA expressly excludes distribution pipelines from the proposed Material Verification requirement.

PHMSA has proposed revisions to the requirements for external corrosion control monitoring. Of specific concern to distribution systems, PHMSA is proposing to change the time when remedial action must be taken to “within one year” of identifying the “deficiency.” Although PHMSA states in the PRIA that its proposed revision would not apply to distribution lines, see PRIA at page 84, the proposed revision to §192.465(d), as written, would apply equally to deficiencies found on transmission pipelines and distribution pipelines. AGA’s specific concerns with PHMSA’s corrosion control proposal are addressed separately; however, AGA notes here that PHMSA has not offered any justification for imposing this time requirement on deficiencies identified on distribution systems or how this revision to corrosion control requirements would impact distribution systems.

In addition to external corrosion control monitoring, PHMSA is proposing to update the criteria for cathodic protection and determination measurements for steel, cast iron, and ductile iron structures found in Appendix D to Part 192. According to PHMSA, Appendix D: Criteria for Cathodic Protection and Determination of Measurements needs to be updated to reflect more recent experience and understanding of cathodic protection and would have no regulatory impact. This is not the case. As described elsewhere in detail, the criteria that PHMSA proposes to remove are primary methods upon which operators rely. Eliminating these criteria would have significant impacts to operators. Although the proposed changes to Appendix D would apply to distribution pipelines as well as transmission pipelines, PHMSA has offered neither justification nor estimate of the impact on either transmission or distribution systems.

PHMSA also has proposed changes to the requirement that pipeline operators maintain a procedural manual for operations, maintenance, and emergencies. Under the existing rule, the required manual must include procedures for starting up and shutting down the pipeline in a manner to assure operation within MAOP limits.
See 49 C.F.R. §192.605(b)(5). PHMSA has proposed to revise this requirement to include procedures for “operating pipeline controls and systems and operating and maintaining pressure relieving or pressure limiting devices.” See Proposed §192.605(b)(5). Despite PHMSA’s statements to the contrary, see PRIA at page 94, the code has never before required operators to include procedures specific for each individual physical control or device in their manual. AGA’s concerns with this addition as it relates to transmission lines are included elsewhere in these comments. However, because the proposed revision would also apply to distribution pipeline systems, AGA notes that PHMSA has not provided justification for imposing this required on distribution, nor has PHMSA evaluated the impact of doing so.

PHMSA has proposed new definitions for “legacy pipe” and “legacy construction” that on their face are not limited to transmission systems. Ironically, however, some of the materials and techniques that are identified as “legacy” are still valid for distribution pipelines under the Pipeline Safety Code. For example, “acetylene welds” are identified as a “legacy construction technique”; however, these welds are permissible under the code for distribution systems: Appendix C to Part 192 (Qualifying Test for Acetylene Welds); §192.225 (identifying welder procedures and not prohibiting acetylene welds). AGA is concerned that by classifying distribution pipelines as “legacy,” PHMSA will be wrongly identifying these pipelines as safety threats.

In addition, AGA believes that several of PHMSA’s proposals related to gathering lines could also have an impact on distribution systems. AGA is concerned that PHMSA’s proposed new definition “gas treatment facility” will have an unintended impact on distribution systems. Local distribution company large volume customers may install strainers (i.e., filters) prior to meters (e.g., rotary meters) to prevent solids and liquids from entering the meter. Because PHMSA’s proposed definition of “gas treatment facility” does not limit its application to gathering lines, this configuration could be deemed to fall under the proposed definition of a “gas treatment facility” and, if so classified, would be subject to the proposed regulatory requirements for gas treatment facilities associated with gathering lines. AGA encourages PHMSA to revise the definition of “gas treatment facility” to limit its application to gathering lines and expressly exempt distribution facilities.

Finally, in numerous locations throughout the Proposed Rule, PHMSA has included the phrases “Each operator of a gas transmission pipeline” (§191.29(a)); “Each operator of an onshore gas transmission pipeline” (§192.13(d)); and “Each operator of transmission pipelines” (§192.67, §192.127, §192.205, §192.319(d)). Since many local distribution companies operate both intrastate transmission and distribution pipelines, these phrases could be interpreted to apply the referenced regulatory requirements to all pipelines being operated by an operator of both transmission and distribution pipelines. AGA does not believe that it was PHMSA’s intention to include non-transmission pipelines and encourages PHMSA to revise these phrases to provide appropriate clarification that the intent of these proposed regulations is to address only gas transmission pipelines and not non-transmission pipelines of an operator. PHMSA could fix this problem by revising the regulation to state, “For gas transmission pipelines, each operator must …”.

In addition to the direct impact that the Proposed Rule would have on distribution systems, the Proposed Rule would also have significant indirect impacts on distribution systems. AGA member companies – local distribution companies (LDCs) – are committed to the continuous enhancement of safety. In support of this...
commitment, many members undertake voluntary actions to help ensure the safe and reliable operation of natural gas pipelines.\textsuperscript{11} In addition to their distribution systems, many LDCs operate a significant number of miles of intrastate gas transmission pipelines that would be subject to the extensive and prescriptive requirements in the Proposed Rule. An unavoidable impact of complying with the prescriptive requirements of the Proposed Rule, many of which AGA believes the costs far outweigh any presumed safety benefits, will be a potential scaling back of voluntary measures on distribution systems due to limited resources.

A perfect example of such a voluntary measure likely to be scaled back is the accelerated pipe replacement programs that exist throughout the nation. This program results in the replacement of aging cast iron and unprotected steel pipe as well as early vintage plastic pipe that has been identified for accelerated replacement to enhance pipeline safety. Ironically, in 2011, Secretary LaHood’s Call to Action called on LDCs and state regulators to work together to develop such programs. The parties hailed to this call and now 38 states and the District of Columbia have specific rate mechanisms that foster accelerated replacement of specific pipelines to modernize and replace aging pipeline infrastructure. In the case of the 12 states without such programs, several no longer have cast iron pipelines in their systems and maintain only small amounts of unprotected steel. Not only are these accelerated replacement programs enhancing safety, but these accelerated pipe replacement programs are also recognized by Environmental Protection Agency (EPA) for reducing methane emissions from distributions pipelines. In fact, in EPA’s recently launched Methane Challenge, one of the best management practices that LDCs can commit to for reducing methane emissions is the replacement of cast iron and unprotected steel pipe.\textsuperscript{12} However, the participation in such programs could be jeopardized as operators are forced to devote resources to compliance with a final rule arising from this proposed rule, instead of such voluntary measures.

Local distribution companies must comply with federal and state regulatory requirements before assigning resources towards voluntary actions, such as accelerated pipe replacement and other voluntary actions such as those that reduce excavation damage, emergency response training with local emergency responders, efforts to create or enhance the company’s geographic information system, and funding for research and development. Local distribution companies will need to seek approval from state utility commissions to continue their current pace of distribution replacement and other voluntary efforts, and the state commissioners will need to balance the cost of regulatory compliance and voluntary initiatives with the impact on natural gas customer rates. Since the cost of regulatory compliance is borne by the customer, state commissioners will only be able to lessen the impact on customers by reducing a company’s voluntary actions.

Given the significant recognized benefits associated with accelerated pipe replacement and other voluntary measures that LDCs undertake, there is a real and significant possibility that such voluntary programs would be scaled back or delayed, as scarce resources are deployed to comply with the mandates of the Proposed Rule. If adopted as written, PHMSA must consider this loss of benefits in its statutorily-required risk assessment.

As discussed, AGA believes the Proposed Rule would have significant direct and indirect impacts on distribution systems. PHMSA has failed to justify, or even acknowledge such impacts, in the Proposed Rule. As a result, PHMSA has not fulfilled its statutory obligation to issue a standard only if based upon a reasoned


determination that the benefits of the intended standard justify its cost. As such, the final rule must be revised so as to explicitly eliminate these impacts to distribution systems.

**D. Definition of Transmission Line & Distribution Center**

PHMSA has proposed a modification to the existing *Transmission line* definition contained in §192.3 by revising the second of three criteria utilized to define which pipelines are *Transmission lines*. PHMSA has also introduced a new definition, *Distribution center*, a currently undefined term used within the definition of *Transmission line*. Under the current definition of *Transmission line*, a pipeline can be considered a *Transmission line* if it meets one of three criteria. PHMSA proposes to modify the second criterion of the *Transmission line* definition by revising the calculation of percent of Specified Minimum Yield Strength (% SMYS), whereas previously it was defined using the “operating pressure” of the pipeline. The proposed definition for *Distribution center* attempts to provide clarification for when pipelines would be subject to the first criteria contained in the definition of *Transmission line* by describing what PHMSA believes to be the attributes of a *Distribution center*. These proposed changes impact whether pipelines would be classified as transmission or distribution and the applicable integrity management, operations, and maintenance activities associated with this definition.

As detailed below, AGA strongly encourages PHMSA to postpone its proposal to revise the definition of *Transmission line* until it can be given appropriate consideration. A modification to the second criterion in the *Transmission line* definition and the creation of a definition for *Distribution center* will result in the transition of some transmission pipelines to distribution and some distribution pipelines to transmission. Until the impact of these changes can be fully considered, AGA recommends that PHMSA not modify the basis for the % SMYS calculation in the second criterion of the *Transmission line* definition. However, AGA appreciates PHMSA’s acknowledgement that *Distribution center* should be defined for regulatory certainty and consistency, and provides PHMSA with suggestions to improve the definition.

As stated above, AGA strongly urges PHMSA not to revise the second criterion of the *Transmission line* definition within this Proposed Rule. The current definition of *Transmission line* has been essentially unchanged since its codification in 1970 with the enactment of the original pipeline safety regulations, with the exception of the clarification of “large volume customer” in the first criteria. Operators have relied on this definition and made significant investments and business decisions based on this definition. Any revision to the definition of *Transmission line* would have substantial and significant impacts for the industry. PHMSA has failed to consider these impacts in the PRIA and has failed to provide any reasoned explanation or justification to support the proposed revision and its departure from the current definition. In fact, in response to comments on the Advance Notice of Proposed Rulemaking suggesting that PHMSA revises the definition of *Transmission line*, PHMSA explicitly stated that the definition of transmission line was “not within the scope of this proposed rule.” See 81 Fed. Reg. 20739. Revisions to a definition that will have such significant repercussions and impacts should not be implemented without thoughtful consideration, which PHMSA has not provided.

Any changes to the second criterion of the *Transmission line* definition should be codified only after thoughtful deliberation and consideration from all impacted stakeholders, and with explanation and reasoned justification. If PHMSA would like to proceed with a revision the second criteria in the *Transmission line* definition,
AGA strongly encourages the formation of a multi-stakeholder advisory group, which would include representatives from PHMSA, NAPSR, FERC, industry, and other stakeholders to evaluate and make recommendations regarding any modification to the Transmission line definition and the potential impact of such modifications. In the meantime, AGA believes that PHMSA should move forward with its proposed definition of Distribution center, subject to AGA’s comments and suggestions identified below.

If PHMSA insists upon changing the second criterion of the Transmission line definition, AGA wants to be clear that it does not support the proposed changes. As stated above, operators have used the current Transmission line definition for over forty-five years. In fact, operators have historically relied upon and are currently using “operates at a hoop stress of 20 percent or more of SMYS,” as a primary determination of Transmission lines. AGA believes the current definition does not need to be modified because pipeline safety is not enhanced by PHMSA’s proposed change. In fact, it can be argued that the proposed change in the calculation of % SMYS, from “operating pressure” to “MAOP,” may have the effect of decreasing overall system safety and diluting transmission integrity management efforts without decreasing risk.

To provide an example, a LDC installing a section of new 12-inch (12.750”), 0.375-inch wall thickness, X-52 grade pipeline in a Class 2 location may choose to perform a hydrostatic strength test at 90% SMYS to plan for future customer expansions and to ensure the integrity of the materials and welds following construction. The established Subpart J pressure test to produce a minimum of 90% SMYS during the test would be 2,925 psig. However, the LDC operator may choose to establish the MAOP of the segment at 720 psig. At the 720 psig MAOP, the line would produce a hoop stress of 23.5% SMYS, and therefore under the new proposed definition would be categorized as a transmission line. However, this pipeline may be a replacement of a segment of a line where the operator’s system operating pressure or Maximum Operating Pressure (MOP) is currently 440 psig due to other system constraints. At the existing system operating pressure or MOP, the new line would operate at 14.5% SMYS, and would be considered a distribution line and would meet all the regulatory and integrity management requirements applicable to distribution pipelines.

Under PHMSA’s current regulations, if a pipeline’s operating pressure reaches or exceeds the 20% SMYS threshold at any time, regardless of the calculated MAOP, it is classified as a transmission pipeline and subject to all corresponding regulatory requirements. The burden is on the operator to track and ensure that the pipeline is classified correctly, regardless of whether the % SMYS is calculated using the hoop stress from operating pressure or MAOP.

The % SMYS criterion within the Transmission line definition is the criteria most closely associated with the risks of the pipeline. The historical differentiation between transmission and distribution lines is linked to the failure mechanism of the pipeline. The 20% SMYS threshold was selected because historical industry research suggested a threshold between those pipelines that would fail by leaking versus failing through a rupture was 20%.

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PHMSA’s proposed action could have broader impacts beyond this rulemaking. Other agencies rely on PHMSA’s categorization of pipe. For example, companies report their miles of transmission and distribution pipe as defined by PHMSA’s regulations in annual reports to PHMSA, and EPA depends on those annual reported transmission and distribution mileage numbers to estimate emissions for the annual Inventory of Greenhouse Gas Emissions in the U.S. A change in PHMSA’s categorization of pipelines would also complicate and potentially undermine EPA’s new voluntary Methane Challenge program for reducing methane emissions, which includes ambitious tiered goals for replacing certain types of distribution pipelines, based on the company’s existing mileage of distribution pipeline of that type – again based on PHMSA’s definition of “transmission” vs. “distribution” pipeline.
The critical point of this distinction is the pressure at which the pipeline is operating at the time of the event, not the established MAOP. For example, if the pipeline is operating at 8% SMYS, data support the assumption the pipeline failure will result in a leak rather than rupture, even if the MAOP is greater than 20% SMYS.

If implemented, the proposed changes will force operators to consider reducing current MAOPs on lines operating with hoop stress less than 20% SMYS. Alternatively, operators may choose to create more transmission mileage for lines with MAOP exceeding 20% SMYS but operating with hoop stress less than 20% SMYS, resulting in assessment requirements and expenditures that exceed the satisfactory level needed. PHMSA currently has separate integrity management regulations for distribution lines operating with hoop stress less than 20% SMYS, and AGA asserts that lines operating at hoop stress less than 20% SMYS should be assessed with distribution integrity regulations. The proposed definition will result in a dilution of transmission integrity resources that should be focused on higher priority segments where rupture is more likely. It will also make it more difficult for operators to effectively plan for future expansion with minimal service disruption and expense to customers. Lines where MAOPs are forced to be reduced will require removing the line from service and retesting it to establish higher MAOPs in the future. This will result in unnecessary service disruptions and costs passed along to the public.

As previously noted, AGA strongly discourages PHMSA from attempting to address the definition of Transmission line, used and relied upon for over forty-five years, within this proposed rulemaking as these changes are substantial and impactful for the industry and should not be implemented without careful deliberation, explanation and reasoned justification. If PHMSA elects to proceed with these definitions under this proposed rulemaking, even with the concerns noted above, AGA provides the following recommendation for PHMSA’s consideration.

AGA encourages PHMSA to add a fourth criterion within the Transmission pipeline definition that would recognize as transmission pipelines those pipelines that operators voluntarily elect to treat as transmission pipelines by applying transmission pipeline requirements and corresponding integrity management principles to them. By allowing operators the flexibility to voluntarily categorize a pipeline as transmission, PHMSA will be removing regulatory obstacles experienced by some operators to applying more stringent integrity management protocols and risk assessments to pipelines, and thus advancing pipeline safety.

AGA offers the following suggested edits to PHMSA’s proposed definition for Transmission line:

Transmission line means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) has a MAOP operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage facility; or (4) is voluntarily determined by the operator to be a transmission line. Note: A large volume customer (factories, power plants, and institutional users of gas) may receive similar volumes of gas as a distribution center.

AGA recognizes PHMSA’s desire to define Distribution center in an effort to ensure consistency and certainty in the identification of Transmission lines. However, PHMSA has failed to provide any justification or

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14 Recent research suggests this threshold is actually at 30% SMYS per Kiefiner/GTI “Leak vs. Rupture Thresholds for Material and Construction Anomalies” 2013.
explanation for its proposed definition. Neither has PHMSA evaluated the impact of the proposed definition, including the impact on states that have already addressed the undefined term by providing their own definition.

Based on AGA’s review of the proposed definition of Distribution center and existing PHMSA interpretations of Distribution center, AGA believes that modifications to the proposed definition would aid in providing a clear and consistent understanding, interpretation, and application of Distribution center. It would, therefore, also provide clarity and understanding to what is a Transmission line, since Distribution center is used to identify Transmission lines under the first criterion in the definition of Transmission line. This clarification will prevent the potential for significant, unintended impacts that may be the result of the determination of Transmission lines, and subsequently the requirements by which pipelines are operated and the methodology used to manage risks on those pipelines.

AGA agrees that defining specific points or locations within gas pipeline systems for the demarcation between distribution and transmission lines will assist in the clarification of Distribution centers. Therefore, AGA supports maintaining references to metering locations, pressure reduction locations, and volume reduction points in the Distribution center definition as proposed by PHMSA. AGA’s proposal below offers additional clarity to the definition of Distribution center:

- Distribution center begins at the initial point where gas entering piping is “used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale.” It should be recognized that local distribution companies have multiple regulator stations and pressure reductions between the initial entry point from the transmission company to their customers.
- A reduction in volume of gas would include a lateral off the main Transmission line.
- Finally, AGA proposes a clear recognition in the promulgated language that piping downstream of a distribution center that is operating above 20% SMYS should be classified as a Transmission line.

Below is AGA’s proposed definition of a Distribution center that takes into account the recommendations above: Distribution center means the initial point where gas volumes are either metered or have pressure of volume enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale, for example:
(1) at a metering location
(2) pressure reduction location, or
(3) where there is a reduction prior to delivery to customers through a distribution line in the volume of gas, such as a lateral off a transmission line.

The complete overhaul of how % SMYS is calculated (MAOP vs. operating pressure), in conjunction with the introduction of a new Distribution center definition that is confusing and subject to multiple interpretations, will result in significant regulatory uncertainties between operators and regulators. In addition, as described above, there are no pipeline safety benefits that will be realized as a result of the proposed change in criteria (2), but there are significant operational and business decision impacts that have not been adequately addressed or even acknowledged within the Proposed Rule or the PRIA.

If PHMSA moves forward with revisions to the Transmission line definition, AGA encourages the development of a multi-stakeholder advisory group to address the second criterion of the definition of
Transmission line. Until then, PHMSA should revert back to “operates at a hoop stress of 20 percent or more of SMYS” and consider adding another criterion to remove regulatory obstacles for actions that will improve pipeline safety. In addition, AGA encourages PHMSA to codify a definition for *Distribution center* that is clear and incorporates AGA’s suggested revisions.

**E. General Record Requirements**

AGA understands that records, whether material or operational, provide pipeline safety regulators with documentation, and certainty of an operator’s compliance with the pipeline safety code. On a prospective basis, AGA recognizes that natural gas pipeline operators will be required to maintain additional records that will be evaluated with a higher degree of scrutiny. AGA, however, has significant concerns with PHMSA’s proposal to enlarge the magnitude of records required to document compliance with all of Part 192 and to impose stringent new standards to validate those records for pipelines currently in service. See proposed 49 C.F.R. § 192.13(e). This represents a reversal of PHMSA’s record retention policy and regulations that regulated entities have relied upon and implemented over decades of construction and service with no substantive explanation or justification.

PHMSA is expressly prohibited from regulating the design, installation and construction of existing pipelines. These prohibitions apply equally to recordkeeping requirements. Therefore, not only is PHMSA prohibited from mandating that operators have reliable, traceable, verifiable and complete records related to pipeline design, installation and construction for existing pipelines, PHMSA is also prohibited from mandating that operators have reliable, traceable, verifiable and complete records related to prior actions where the pipeline safety regulation in effect at the time did not require documentation.

As written in the Proposed Rule, these changes would apply equally to transmission and distribution pipelines. In addition, because these requirements would be added to what PHMSA and operators understand to be a “retroactive” subpart of pipeline safety regulations, the proposed recordkeeping obligations would retroactively apply to existing pipelines as well as pipelines installed after the effective date of the rule. For existing pipelines, the result would be an ambiguous requirement for operators to re-document aspects of their operation and material specifications to demonstrate “compliance” with Part 192. PHMSA must recognize their limited authority to promulgate “retroactive” regulations and the significance of the regulatory impact that proposed §192.13(e) would have. AGA further comments on the impacts of retroactive regulations in Section III.B of these comments. PHMSA should revise the Proposed Rule so that record requirements are applied prospectively, and the codified heightened quality standard – traceable, verifiable, and complete – is applied limitedly and prospectively to those MAOP records for gas transmission pipelines.

**PHMSA Misrepresents the Scope and Significance of Its Proposed Recordkeeping Requirements**

PHMSA modestly describes its proposed requirements in §192.13(e) as “clearly articulat[ing] the requirements for records preparation and retention and require[ing] that records be reliable, traceable, verifiable, and complete.” See 81 Fed. Reg. 20808. Within its PRIA, PHMSA describes proposed §192.13(e) as elaborating on the general recordkeeping requirement in §192.603: *General provisions*. See PRIA, page 95. Contrary to PHMSA’s statements, §192.603(b) does not contain a general requirement to maintain records for operating, maintaining, and repairing the pipeline. Instead, §192.603(b) merely requires operators to keep records necessary to administer its manual of written procedures for conducting operations and maintenance activities and for
emergency response. Nothing in either §192.603(b) nor §192.605: Procedural manual for operations, maintenance, and emergencies, imposes an obligation to maintain records regarding the operation, maintenance, or construction of a specific pipeline. §192.13(e) imposes significant new recordkeeping requirements on operators of transmission and distribution pipelines. In fact, PHMSA’s proposal to add this broad recordkeeping requirement demonstrates that the code never contained such a requirement. In the detailed comments below and throughout this document, AGA demonstrates the lack of justification for some of these new requirements and the overwhelming challenges associated with overbroad retroactive record requirements.

First, the Proposed Rule would require that operators “make and retain records that demonstrate compliance with [49 C.F.R. § 192].” Proposed 49 C.F.R. §192.13(e). By adding this all-encompassing and vague requirement, PHMSA has added an obligation for operators of all transmission and distribution pipelines to document compliance with every aspect of Part 192 to a new standard that amounts to a near impossibility. In other words, an operator now has an obligation to document compliance where there has never been a requirement to document or retain records within the specific sections of pipeline safety code. In essence, the broadly applicable recordkeeping requirement proposed in §192.13(e) would make all existing record requirements extraneous and repetitive. There are numerous recordkeeping requirements throughout the Pipeline Safety Code that demonstrate PHMSA’s ability to impose an affirmative and clear obligation to maintain records. For example, §192.517 clearly requires operators to maintain a pressure test record, including the information that is required to be included in the record. The far-reaching requirements in §192.13(e), coupled with the fact that it is located in a “retroactive” subpart, would require existing pipelines to create records demonstrating past and future compliance where existing code does not require these records. This exercise in developing records would divert resources and attention from other activities that advance pipeline safety.

Second, the Proposed Rule would require that all records be “reliable, traceable, verifiable, and complete” (RTVC). Proposed 49 C.F.R. §192.13(e)(2). In the past, PHMSA has suggested that MAOP records need to be “traceable, verifiable, and complete” (TVC). It is unclear what purpose, if any, PHMSA is attempting to achieve by adding the undefined term “reliable” to the phrase because PHMSA fails to address or even acknowledge the addition. Regardless, AGA reminds PHMSA that there is neither a statutory requirement nor regulatory requirement that a record be RTVC or even TVC. As discussed below, this language originated in an NTSB recommendation provided to the California Public Utilities Commission and directed at only one operator. AGA’s position on the appropriateness and legality of PHMSA’s proposed RTVC standard is discussed in more detail below, but notes that by explicitly adding a retroactive requirement that records be RTVC, PHMSA is retroactively changing the standard on the validity of records years after the records have been created.

Third, PHMSA would require that for certain existing “pipeline material . . . for which records are not available,” operators re-establish pipeline material documentation. Proposed 49 C.F.R. §192.13(e)(3). As drafted, this provision is confusing and ambiguous. PHMSA’s use of the term “pipeline material” in proposed §192.13(e)(3) is undefined. Moreover, PHMSA does not describe the types of missing documents that would trigger this obligation to re-establish pipeline material. As written, it can be assumed that PHMSA is referencing all the material documents outlined in §192.607. But §192.607 applies only to a limited subset of transmission pipelines.

AGA notes that §192.709 requires that operators maintain for transmission lines limited repair records, as well as limited records of patrols, surveys, inspections and tests. This section also does not require the same sort of broad recordkeeping requirements contemplated by the proposed revisions and was only added in 1996.

If PHMSA’s reference to §192.607 is merely a reminder that §192.607 applies to those pipelines that meet the applicability in proposed §192.607(a), then subsection §192.13(e)(3) is redundant. However, AGA is concerned that PHMSA is imposing, through this reference, an obligation to re-establish material properties through the proposed §192.607 process to all transmission and distribution pipelines that are missing material records. There is no support for such broad application of §192.607. As PHMSA is aware, there currently is no explicit regulatory requirement that operators retain documentation of pipeline material, as shown by the proposed additions of §192.67 Records: Materials and §192.205 Records: Pipeline Components. Therefore, §192.13(e) could impact a significant amount of existing transmission and distribution pipelines, due to the fact that operators were never required to maintain these records and given direct and contrary guidance on the records that must be maintained. AGA provides further comments on §192.607 in Section IV.A.2 of these comments.

Finally, through this new requirement, PHMSA would require operators of transmission pipelines to keep records for the retention period specified in Appendix A. Proposed 49 C.F.R. §192.13(e)(1). PHMSA’s incorporation of an obligation to keep records in accordance with Appendix A fails to recognize that PHMSA itself describes Appendix A as for “convenience only.” Proposed Appendix A. As described in more detail in Section IV.I.1 of these comments, there are significant errors in both the scope of requirements included in Appendix A (e.g., including record requirements applicable only for distribution pipelines) and the inclusion of code sections that impose no obligation to maintain records. By including in proposed §192.13(e)(2) a requirement to follow Appendix A, PHMSA has incorporated by reference Appendix A and all of its inconsistencies and mistakes, as a requirement for transmission operators to follow. More so, by referring to the “retention period specified in Appendix A,” PHMSA appears to be revising and adding new record retention requirements through incorporation by reference to Appendix A. Many of these record retention requirements are not found in the code language and are new, sometimes retroactive, obligations to maintain records for a specified period of time.

As described, the requirements that would be imposed on operators of transmission and distribution pipelines through proposed §192.13(e) are new and significant and cannot be described as a clarification of existing requirements. PHMSA has not offered any reasoned justification nor explanation supporting this proposal.

**PHMSA Misstates its Authority to Impose Such Significant Recordkeeping Requirements and Fails to Estimate its True Impact**

For justification of the requirements, PHMSA points to Congressional mandates from the 2011 pipeline safety authorization in support. See 81 Fed. Reg. 20808. However, PHMSA’s justification is lacking. There is no statutory requirement to require that all pipeline operators retroactively document compliance with the regulations, maintain records that are RTVC, or re-establish material properties. Instead, Section 23 of the Act merely requires that operators verify whether their existing records accurately reflected the physical and operational characteristics of a specific set of pipelines and report to PHMSA those pipelines with records insufficient to confirm the established MAOP.17 For these pipelines with insufficient records, the Congressional mandate requires that operators reconfirm the MAOP. Importantly, the Section 23 record verification requirements only apply to transmission pipelines in Class 3 and 4 locations and Class 1 and 2 HCAs, whereas the...
majority of the proposed §192.13 requirements would apply broadly to all transmission pipelines as well as distribution pipelines. The proposed §192.13(e) is overbroad, unjustified, and outside the scope of PHMSA’s organic statute and the Section 23 Congressional mandate. Further, PHMSA’s authority is limited by its obligation to consider the costs and benefits associated with the requirement. See 49 U.S.C. § 60102(b)(2)(C), (D), which PHMSA has failed to accurately estimate or consider. It should be noted that nowhere in this mandate does Congress require operators to retroactively create records that previously were not required to be created or maintained.

Furthermore, PHMSA expressly lacks the authority to impose such retroactive regulations. Absent express authority from Congress, regulatory agencies lack the authority to promulgate retroactive regulations. Congress has not provided PHMSA with express authority to impose the retroactive recordkeeping regulations found in proposed §192.13(e). In fact, it’s quite the opposite. Congress has expressly prohibited PHMSA from retroactively regulating the design, installation, construction, initial inspection, and initial testing of existing pipelines. Requiring operators to retroactively document these aspects of an existing pipeline as proposed §192.13(e) is not authorized and is expressly prohibited. PHMSA is also prohibited from mandating that operators have reliable, traceable, verifiable, and complete records related to prior actions where the pipeline safety regulation in effect at the time did not require documentation.

Despite the significant impacts that would be imposed through §192.13(e), PHMSA has treated the impacts and costs as minimal and already realized by operators in the PRIA. These assumptions are incorrect and lead to a significant underestimate of the costs.

PHMSA’s sole basis for the costs associated with proposed §192.13(e) is its prior estimate that it would take operators 20 hours to complete a records check for 1,440 annual reports that PHMSA required in response to the Congressional Mandate, Section 23(a) and (b). First, PHMSA’s estimate of 20 hours is extremely low. Operators actually spent a considerable amount of time to complete the required records verification. Second, for the annual report, PHMSA was requesting data on transmission pipelines in Class 3 and 4 locations and Class 1 and 2 HCAs. However, proposed §192.13(e) would apply to all transmission pipelines as well as distribution pipelines.

The more significant flaw in PHMSA’s estimate of costs is that PHMSA is merely assessing the cost of verifying existing records, whereas, as described above, proposed §192.13(e) imposes obligations well beyond “verifying” existing records. Proposed §192.13(e) would require existing pipelines to newly document compliance with Part 192, impose a more stringent authentication requirement on existing records, and require Material Verification where records do not meet the more stringent requirements. PHMSA has failed to address these costs. PHMSA also has failed to address any benefit associated with proposed §192.13(e). See PRIA, page 128 (“PHMSA did not have information to estimate the benefits of this provision from the pre-statutory baseline to accompany the estimate of such costs.”).

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19 See 49 U.S.C. § 60104(b).
20 The flaws in PHMSA’s assumptions regarding the cost of Material Verification are addressed in AGA’s comments on proposed Section 607.
Based on this deficient analysis of the costs and benefits of such an expansive and burdensome recordkeeping requirement, PHMSA’s proposed §192.13(e) cannot be said to be based “upon a reasoned determination that the benefits of the intended standard justify its costs.” See 49 U.S.C. § 60102(b)(5).

Application of Reliable, Traceable, Verifiable and Complete

Since 2010, AGA has closely considered PHMSA’s use of the phrase, “traceable, verifiable, and complete” – the precursor to “reliable, traceable, verifiable, and complete.” The first use of this phrase that AGA is aware of was in a NTSB safety recommendation to an intrastate operator in its report on the natural gas pipeline incident in San Bruno, California, which used the term TVC records. Following the release of this NTSB report, PHMSA referenced TVC records in its Advisory Bulletin ADB-11-01, issued January 4, 2011. In ADB-11-01, PHMSA suggested that TVC was the mandatory standard for MAOP record sufficiency. That position is inconsistent with current regulations and past guidance issued by PHMSA pertaining to records. There is no TVC or RTVC requirement found in the Part 192. Nor is there a TVC or RTVC standard found in any Congressional mandate.

AGA has significant concerns with the proposed application of the RTVC standard, both retroactively and prospectively.

In the retroactive context, PHMSA is proposing to raise the bar on the quality of historic records necessary to comply with documentation requirements of Part 192. Absent specific Congressional authority, agencies lack the authority to promulgate retroactive regulations. PHMSA is expressly prohibited from retroactively regulating the “design, installation, construction, initial inspection, or initial testing” of existing pipelines. By retroactively raising the standard of quality applied to records, PHMSA is impermissibly altering regulatory compliance of past actions by operators of transmission and distribution pipelines alike. Those operators with records of past actions that do not meet the RTVC standard will be immediately out of compliance, with no regulatory option for achieving compliance. In short, PHMSA lacks the authority to promulgate a retroactive RTVC standard. Pursuant to the Congressional Mandate, however, operators have reviewed their records for MAOP in Class 3 and 4 locations and Class 1 and 2 HCAs, and, following PHMSA’s guidance, have attempted to apply the TVC standard to

21 Pipeline Accident Report: Pacific Gas and Electric Company - Natural Gas Transmission Pipeline Rupture and Fire - San Bruno, California - September 9, 2010, p. 133, NTSB/PAR-11/01: PB2011-916501: Notation 8275C (NTSB Aug. 3, 2011)(NTSB Recommendation P-10-2 called for PG& E to “[a]gressively and diligently search for all [records] relating to pipeline system components . . . in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had [an MAOP] established through prior hydrostatic testing, and stated that these records should be “traceable, verifiable, and complete.”).


23 Georgetown Univ. Hosp. v. Bowen, 488 U.S.204, 208 (1987) (“[r]etroactivity is not favored in the law;” “a statutory grant of legislative rulemaking authority will not, as a general matter, be understood to encompass the power to promulgate retroactive rules unless that power is conveyed by Congress in express terms.”)


25 Georgetown, 488 U.S. at 216 (Scalia, J., concurring).

26 AGA recognizes that PHMSA has proposed §192.607, which prospectively would require a certain class of transmission pipelines that do not have RTVC record of specific material properties to undergo testing. As noted elsewhere in the comments, proposed §192.607 is not an adequate or reasonable option for achieving compliance: (1) proposed §192.607 would not apply to all of the pipelines that the RTVC standard would; (2) proposed §192.607 does not alleviate, nor is it in lieu, of any compliance with an RTVC records requirement; and (3) the requirements of proposed §192.607 are unreasonable.
those records. AGA members will continue to follow this approach for verifying MAOP, but believe strongly that a codified RTVC standard cannot be applied retroactively.

The broad application of the RTVC standard prospectively is equally problematic. PHMSA’s original application of the TVC standard was limited to records documenting MAOP. This guidance was provided in PHMSA’s Advisory Bulletin ADB-11-01. See 76 Fed. Reg. 1506. This limited application was confirmed the following year when PHMSA issued Advisory Bulletin ADB-2012-06,27 which provided guidance on what it means for a record to be “traceable, verifiable, and complete” for purposes of establishing MAOP. PHMSA now proposes to expand the applicability of the TVC to all records under Part 192 and to further magnify the requirement by adding the term “reliable.” AGA does not believe that either expansion is appropriate.

First, AGA strongly encourages PHMSA to remove the term “reliable”. PHMSA has failed to define the term or acknowledge this departure from its guidance. By providing no justification for the inclusion of this term, the method of compliance remains incredibly ambiguous and increases regulatory uncertainty as to whether a record will ever be able to meet this standard.

Second, AGA believes that it is inappropriate to expand the applicability of this heightened standard to all records under Part 192, without analyzing the value and purpose of each record requirement and determining where TVC records are truly needed. The records that are required by Part 192 serve different purposes and goals. Some records, such as pressure test records required by §192.517, serve to provide documentation as to the strength and corresponding MAOP of a pipeline. Other records, such as operator qualification records required by §192.807, serve to ensure that qualified individuals are performing tasks on pipelines and pipeline facilities. Each record is distinct in the purpose that it serves. AGA believes that the application of a heightened quality standard such as TVC should recognize and distinguish among these purposes and apply only to the most critical records – specifically, those records relied upon for determining MAOP under §192.619. AGA believes that such limited application is warranted, given the Congressional Mandate and NTSB recommendations related to the documentation of MAOP. The effect of considering all records to be of such critical importance that a heightened RTVC standard should apply, is that no records are of such importance.

Given PHMSA’s proposal to codify the RTVC standard, AGA believes it appropriate to revisit and codify the definitions of “traceable, verifiable and complete” based on operator’s and PHMSA’s experience with applying the definitions since 2012. AGA believes that the following revised definitions of TVC that were developed in consensus with other trade associations and based on the original definitions found in the 2012 Advisory Bulletin can be applied generally and reflect PHMSA’s intent to ensure quality records:

*Traceable, verifiable, and complete* means that a single quality record, or a combination of records, related to the maximum allowable operating pressure of a gas transmission pipeline:

1. can be clearly linked to information about a pipeline segment or facility and is finalized as evidenced by a signature, date, or other appropriate marking or
2. has other similar characteristics that support its validity.

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A single quality record can be traceable, verifiable, and complete. However, in some situations, complementary, but separate, documentation may be necessary. In determining whether a record is traceable, verifiable, and complete, due consideration shall be given to the standards and practices in effect at the time the record was created.

AGA believes that by codifying the TVC definition, PHMSA will be providing the regulated community with a clearer standard as to expectations for records. AGA’s proposed definition is consistent with PHMSA’s recognition that a single, quality record is verifiable.28 In addition, AGA’s definition recognizes that record and data management is an evolving process and that retaining an original document is not reasonable, feasible or practical.

As previously noted, PHMSA’s proposed application of the RTVC standard would also apply to distribution systems. PHMSA has provided no justification for applying this standard outside of transmission lines, nor has PHMSA provided any assessment of the impact to distribution systems. As PHMSA is aware, distribution pipelines operate at lower stress levels than transmission pipelines and generally present less risk than higher pressure, higher stress transmission pipelines. As such, there is less justification for imposing the same stringent requirements for transmission pipelines on distribution systems. Moreover, because the TVC standard has only been discussed in the transmission context, PHMSA and distribution operators need time to evaluate the potential impact and feasibility of applying such a standard – a standard that could only be phased in over time. For these reasons, AGA believes that any application of RTVC or TVC should be applied solely to transmission pipelines.

AGA Encourages PHMSA to Incorporate the Following Changes Into Any Proposed Rule

PHMSA has failed to adequately explain or support the proposed recordkeeping requirements on transmission and distribution pipelines operators. PHMSA’s proposal represents a significant shift in PHMSA’s past regulatory requirements for documentation and record retention. Moreover, there is no justification for such broad application of the proposed requirement. Consistent with the above comments, AGA provides PHMSA with the following suggested changes to the proposed code language:

§192.13(e)
(e) Each operator must make and retain records that demonstrate compliance with the explicit record keeping requirements of this part.
(1) Operators of transmission pipelines must keep records for the retention period specified in Appendix A.
(1) For gas transmission pipelines installed after [insert date that is one year after the effective date of the rule], maximum allowable operating pressure records must be reliable, traceable, verifiable, and complete.
(2) Traceable, verifiable, and complete means that a single quality record, or a combination of records, related to the maximum allowable operating pressure of a gas transmission pipeline:
   (i) can be clearly linked to information about a pipeline segment or facility and is finalized as evidenced by a signature, date, or other appropriate marking, or
   (ii) has other similar characteristics that support its validity.
   (iii) A single quality record can be traceable, verifiable, and complete. However, in some situations, complementary, but separate, documentation may be necessary. In

28 Letter from John A. Gale, Director, PHMSA, to Christina Sames, Vice President, American Gas Association (July 31, 2012).
determining whether a record is traceable, verifiable, and complete, due consideration shall be given to the standards and practices in effect at the time the record was created.

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

F. AGA’s Alternative Framework

AGA’s member companies are deeply committed to pipeline safety and following the Congressional mandates included in the Pipeline Safety Act of 2011. AGA’s member companies are also committed to going above and beyond existing regulations and legislation to improve pipeline safety in a thoughtful and reasonable fashion. In 2011, AGA released its Commitment to Enhancing Safety, which represents AGA membership’s commitment to the continued enhancement of pipeline safety through voluntary actions. The document has been updated several times since its inception and includes a commitment to “advance integrity management programs and principles to mitigate system specific risks. This commitment includes operational activities, repair, replacement, or rehabilitation of pipelines and associated facilities where it will most improve safety and reliability.” AGA wants to continue with this commitment, but the prescriptive requirements which PHMSA proposed will negate many integrity enhancements resulting from this commitment.

In addition to the topic specific comments that follow in this document, AGA would like to provide PHMSA with an alternative framework for consideration. AGA’s proposal is in response to PHMSA’s prescriptive and complex proposals related to Material Verification (§192.607), MAOP Verification (§192.624), and Reliability Assessments Outside of HCAs (§192.710). AGA believes its approach is more direct, would be easier to enforce, and would focus resources on the highest risk areas, as opposed to meeting prescriptive regulations that would divert resources towards other areas. Most importantly, AGA’s approach would achieve PHMSA’s purpose in a manner that would further advance pipeline safety.

AGA’s alternative approach addresses Material Verification, MAOP Verification and Reliability Assessments Outside of HCAs consistent with Section 23(c) and (d) of the Pipeline Safety Act of 2011 and the intent of NTSB Recommendation P-11-14. AGA’s alternative framework is an integrated approach with all three pieces, Material Verification, MAOP Verification and Reliability Assessments Outside of HCAs, working in harmony to meet a common goal: advancing pipeline safety. These three pieces cannot be decoupled. Given the enormity of the Proposed Rule and the limited time in which to comment, AGA’s alternative framework provides the structure for each component. With additional time, AGA is willing to develop and provide to PHMSA additional detail, including proposed regulatory language and impact estimates. AGA looks forward to developing effective regulations with PHMSA and providing more details in the near future. AGA’s alternative proposal in these three areas is based on the following:

Material Verification: For all gas transmission pipelines, operators will capture available material verification information necessary for MAOP and remaining strength calculations that is visible or measurable when the pipeline is excavated during the normal course of business, such as wall thickness. When a coupon or cylinder of pipe is removed from service by a cutout, the pipe sample will be destructively tested for material verification. If there is a component removed from service and other...
components remain with attributes that are assumed to be similar, then the operator will perform testing on the removed component to verify the material properties or pressure rating of the similar components that remain in service. As new tools and technologies, including advanced in-line inspection and non-destructive testing (NDT), become available, those technologies can be used in place of destructive testing where material verification is necessary. This process will be implemented through modifications to company procedures, not through a formalized plan.

**MAOP Verification**: Operators will execute two separate sets of actions, which can be performed simultaneously or separately.

1. First, operators will either pressure test or utilize an alternative technology that is determined to be of equal effectiveness on high-risk gas transmission pipelines that do not have a record of a Subpart J pressure test or are currently utilizing §192.619(c) for MAOP Determination. Operators will systematically address these pipelines with a three-tiered approach.
   - In tier #1, operators will verify the MAOP of pipelines located in HCAs and operating at a pressure greater than 30% SMYS.
   - In tier #2, operators will verify the MAOP of those pipelines in Class 3 & Class 4 pipelines that operate greater than 30% SMYS.
   - In tier #3, operators will expand the MAOP Verification requirements to all remaining gas transmission pipelines in HCAs, Class 3 and Class 4 locations that operate less than or equal to 30% SMYS. The requirements for this third subset of pipelines would be expanded to include a methodology specifically designed for segments with small potential impact radius, similar to Method 5 in the MAOP Verification proposal from PHMSA.

2. The second set of actions that can occur either simultaneously or subsequent to #1 above is the use of in-line inspection tools on all gas transmission pipelines, regardless of class location, that are able to accommodate inspection by means of an instrumented in-line inspection tool. The ILI tool used would be qualified to find defects that would fail a Subpart J pressure test.

**Integrity Management Outside HCAs**: Operators will perform reliability assessments on all Class 3 & 4 transmission pipelines and transmission pipelines able to accommodate inspection by means of an instrumented in-line inspection tool. The integrity assessment options should mirror those proposed by PHMSA in §192.710, but should be revised to reflect AGA’s concerns that are described in the comments in Section IV.D where AGA proposes Subpart Q: *Reliability Assessments Outside of HCAs*.

PHMSA’s proposal for Material Verification only applies to pipelines in HCAs and Class 3 and 4 locations, which is 37,630 miles, or 13% of the onshore gas transmission pipeline miles. AGA’s framework would apply to all 301,791 miles of gas transmission pipelines, or 100% of the system. AGA’s proposal for expansion of integrity management assessments covers 128,322 pipeline miles, and eliminates the need for costly identification and maintenance of MCAs. When combining these pipelines with the 19,823 miles located in HCAs, AGA’s framework equates to integrity management assessments being performed on 49% of the 297,826 miles of onshore gas transmission pipelines, a number that has increased annually since being tracked by PHMSA, and will continue to expand due to AGA’s commitment to voluntary actions. This is a substantial increase from the 50,940 pipeline miles, or 17% of the system, that is covered by the existing regulations and PHMSA’s proposal.
In addition to Section 23 of the Pipeline Safety Act of 2011 and NTSB Recommendations P-11-14, PHMSA points to NTSB P-11-15 as the justification for its proposed requirements. AGA supports the intent of NTSB Recommendation P-11-15, however AGA believes it is directly related to integrity management and its inclusion in the discussion on Material and MAOP Verification complicates the issues. Therefore, AGA recommends that the intent of this recommendation be met through the requirements in Subpart O: Integrity Management, and further recommends an explicit requirement for addressing manufacturing and construction related threats on pipelines that meet the applicability of either §192.710 or AGA’s proposed Subpart Q (introduced in Section IV.D of these comments).

AGA can maintain its support for this alternative framework to PHMSA’s Material Verification (§192.607), MAOP Verification (§192.624), and Reliability Assessments Outside of HCAs (§192.710) proposal only if AGA’s alternative framework is adopted collectively and with the acceptance of AGA’s proposed definition of Able to accommodate inspection by means of an instrumented n-line inspection device, which is discussed in Section IV.C of these comments. PHMSA’s adoption of this definition is critical for the success of this proposal, as the solutions AGA provides are closely linked to the ability to efficiently utilize the capabilities of multiple commercially available conventional free-swimming in-line inspection tools. AGA’s alternative proposal is broader and would cover more pipeline miles than PHMSA’s proposal and eliminates the need for Moderate Consequence Areas because AGA’s proposal incorporates existing classifications of pipelines or applies generally to all gas transmission pipelines.

AGA’s notes to PHMSA that this proposed framework, if considered by PHMSA, is a complete and comprehensive package. AGA would only be able to support this framework without modification or expansion as proposed in these comments. Finally, AGA is providing detailed remarks on nearly every element of PHMSA’s Proposed Rule. Each of those topic specific comments should be carefully considered independently and separately from this alternative proposal being offered by AGA.

IV. DETAILED COMMENTS ON TOPIC SPECIFIC AREAS

A. Introduction to IVP Related Comments

In the Proposed Rule, PHMSA has introduced new regulatory requirements to address MAOP and Material Verification, as well as revisions to the existing MAOP Determination requirements:

- §192.607 Verification of Pipeline Material: Onshore steel transmission pipelines
- §192.619 Maximum Allowable operating pressure: Steel or plastic pipelines
- §192.624 Maximum allowable operating pressure verification: Onshore steel transmission pipelines

PHMSA describes its proposed MAOP and Material Verification requirements as addressing Section 23 of the Pipeline Safety Act of 2011 and related NTSB recommendations. See 81 Fed. Reg. 20812-15. The scope of PHMSA’s proposed regulation, however, goes beyond what was mandated or contemplated by Congress in Section 23. Due to the significant expansion of the scope of pipelines covered under the Proposed Rule, operators will be required to simultaneously address pipelines that were of highest concern to Congress, as addressed in the Congressional Mandates contained in Section 23, and pipelines that were not included in the Congressional Mandates. The result
is a proposal that fails to follow the statutory mandates that PHMSA consider timing, cost, service disruptions and alternative technology in carrying out these mandates. See 49 U.S.C. §60139(c), (d).

There has been significant discussion and debate over the best way to approach these topics. These discussions included PHMSA’s public workshops on the proposed Integrity Verification Process, which PHMSA described as addressing both the establishment of MAOP and material documentation. Through these discussions, AGA has remained committed to working with PHMSA to address these topics in a clear, reasonable, and simple manner.

AGA is providing detailed comments on PHMSA’s specific proposals in the following sections. However, given the significant regulatory history on these topics, AGA encourages PHMSA to view our comments in the context of historical regulatory requirements as well as AGA’s on-going commitment to, and positions on, addressing MAOP determination and material verification.

The Evolution of Minimum Federal Safety Standards for Natural Gas Pipelines

A realistic discussion on MAOP determination and material properties can only be accomplished by first establishing the foundation of where the present pipeline safety regulations (Part 192) originated and how they have evolved over time.

It is critical to note that approximately 57% of natural gas transmission pipelines in service today were installed prior to November 1970, when the federal government first promulgated regulations for natural gas pipelines. Although there were no federal natural gas pipeline safety regulations in effect prior to 1970, these pre-1970 pipelines were generally installed with MAOPs established under ASA B31.1 American Standard Code for Pressure piping (an industry consensus standard (1935-1951)), ASME B31.8 Gas Transmission and Distribution Piping Systems (a consensus standard (1952 and after)) and/or individual company standards which were largely based upon ASA/ASME consensus standards. In addition, prior to the inception of the federal code, several states had individual state pipeline safety regulations that were predicated on these consensus standards. These industry consensus standards formed the basis for the original pipeline safety regulations, including Design, Installation and Testing, which are key attributes for MAOP determination. For example, an examination of the ASA-B31.1.8-1955 standard confirms that the ASA standard includes the identical steel pipe design formula, class location factors and post construction testing requirements (as defined in 841.4 Test Requirements) that were included in the original 49 C.F.R. Part 192 promulgated in 1970. These consensus standards provided valuable guidance for operators on the safety margins built into the pre-1970 pipelines at the time of their design, construction, and post-construction pressure testing. MAOPs determined under the consensus standards were established through logical, technical, and sound engineering methods, entirely consistent with the requirements prescribed in current regulations.

In 1968, Congress enacted the Natural Gas Pipeline Safety Act of 1968, which led to the creation of federal pipeline safety regulations. Congress recognized that existing pipelines had been designed, constructed, and pressure tested consistent with industry consensus standards and explicitly omitted them from being subject to the new regulatory requirements that would be developed as a result of the 1968 Act:

No later than twenty-four months after the enactment of this Act, and from time to time thereafter, the Secretary shall, by order, establish minimum Federal safety standards for
the transportation of gas and pipeline facilities. Such standards may apply to the design, installation, inspection, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. Standards affecting the design, installation, construction, initial inspection, and initial testing shall not be applicable to pipeline facilities in existence on the date such standards are adopted [emphasis added].

Consistent with the 1968 Act, there was recognition when 49 C.F.R Part 192 was implemented that there were no recordkeeping requirements in place for operators to document the design, construction or pressure testing that was completed during the construction of these pre-regulation pipelines. It was for this reason that §192.619(a)(3), the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in (a)(1), and §192.619(c), known as “the grandfather clause”, was included as part of the original 49 C.F.R. Part 192 rule implemented in 1970.

The fundamental methods prescribed in Part 192 for determining a pipeline’s MAOP have not changed since the inception of the federal pipeline safety code in 1970. Establishing MAOP is a critical element of operating a pipeline safely. MAOP determination for both distribution and transmission pipelines is performed through the requirements found within §192.619. And industry standards in place prior to federal pipeline safety regulations included standards for pipeline design, installation and testing, including MAOP determination. The one thing that has changed, over time, is a recognition of the importance of certain records. Historical focus was primarily on the quality of the work, not the record that the work was completed or the specific details of the work.

The natural gas industry is no different from other industries that face the monumental challenge of maintaining records of assets that were constructed many years in the past and which pre-dated the digital age. One can imagine the challenges of keeping detailed physical paper records on every pipeline segment, some of which are decades old, and locating those records when they are needed. Some of the original installation records used to establish the MAOP may now be missing or judged as incomplete by today’s standards, despite the fact that they met the requirements at the time the record was created. Even with the implementation of 49 C.F.R. Part 192 in 1970, the regulations did not specifically define the requirements for documenting and maintaining MAOP and material records. While §192.603(b) General provisions, requires operators to keep records necessary to administer the procedures established under §192.605 Procedural manual for operations, maintenance, and emergencies, there are no explicit requirements to maintain records supporting MAOP determination or material records. Only §192.517, Records, requires detailed information to be retained regarding post-construction pressure test records for pipelines.

AGA Maintains its Position that a Clear and Simple Solution to MAOP and Material Verification is Necessary

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29 Natural Gas Pipeline Safety Act of 1968, Section 3(b) (emphasis added).
30 AGA recognizes that §192.620 Alternative maximum allowable operating pressure for certain steel pipelines, §192.621 Maximum allowable operating pressure: High-pressure distribution systems and §192.623 Maximum and minimum allowable operating pressure; Low pressure distribution systems, may also be used to determine the MAOPs of transmission lines and distribution lines in certain specific circumstances.
31 PHMSA has proposed to fill this record gap by for the first time requiring operators to maintain records on material properties and MAOP Determination. See proposed §192.67 Records: Materials, §192.127 Records: Pipe Design, §192.205 Records: Pipeline components; §192.619(f) (MAOP Determination records).
In July 2013, PHMSA first introduced the Draft Integrity Verification Process (IVP) Flow Chart for industry review and discussion. At the August 7, 2013 IVP workshop in Washington, D.C., PHMSA described the four “basic principles of IVP approach” as follows: (1) apply to higher risk locations, (2) screen segments for categories of concern (e.g. “grandfathered” segments), (3) assure adequate material and documentation, and (4) perform assessments to establish MAOP.

AGA and other interested parties submitted comments to the IVP Workshop docket for consideration on the Draft IVP Flow Chart. As highlighted in AGA’s comments on the draft Integrity Verification Program and in these comments on the Proposed Rule, AGA maintains its position as follows:

1. AGA supports meeting the Congressional mandate of reconfirming MAOP for transmission pipelines in Class 3 and 4 locations and Class 1 and 2 HCAs that have insufficient records to confirm MAOP. See 49 U.S.C. §60139(c).
2. AGA supports meeting the Congressional Mandate requiring testing to confirm the material strength of previously untested gas transmission pipelines in HCAs that operate at a pressure above 30% SMYS using safe testing methodologies, including pressure testing, ILI and other alternative methods determined to be of equal or greater effectiveness. See 49 U.S.C. §60139(d).
3. AGA maintains that pipelines with test records of a 1.25 MAOP pressure test have a valid MAOP through §192.619(a)(2), which is supported by NTSB Recommendation P-11-15. A minimum test pressure of 1.25 times MAOP enables an operator to confirm the stability of manufacturing and construction-related anomalies. AGA does not believe additional documentation or testing is necessary or should be required for these pipelines.
4. For remaining strength calculations, operators have always used supported, sound engineering judgements or conservative engineering assumptions that functionally serve as safety factors when there are specific gaps in information. AGA believes that these judgments or assumptions are supported and recognized by Part 192 and are sufficient to make conservative calculations.
5. With actions to meet the Congressional mandates to reconfirm MAOP, and testing to confirm the material strength of previously untested gas transmission pipelines, AGA does not agree with regulations requiring operators to further verify the physical characteristics of pipelines and various appurtenances through additional testing and documentation beyond what has been historically required by the regulations.
6. AGA does not support a new requirement that operators obtain and retain records detailing extensive material properties and pipeline attributes for new and fully replaced pipelines, fittings, valves, flanges or components beyond what is currently required by Part 192.

AGA maintains that the ability to meet Congressional mandates in a clear and simple manner is critical for implementation and regulatory certainty. PHMSA’s draft IVP Flow Chart conflated the testing requirements of Subpart J - Test Requirements and Subpart L - Operations, with an expansion of the Integrity Management Program.

AGA submitted four separate sets of comments that included positions applicable within this proposed rule. See Appendix C, D, E & F. PHMSA statement that it has “considered and incorporated stakeholder input, as appropriate” is not an adequate response to those comments. As PHMSA acknowledges, the topics covered by the IVP workshop are also addressed in this Proposed Rule. As such, AGA incorporates its IVP comments in these comments. AGA expects that PHMSA will not only address AGA’s comments within this document but also within the four previously submitted sets of comments on these topics from the IVP workshop.

requirements in Subpart O - *Gas Transmission Pipeline Integrity Management*. This ultimately created an unnecessarily complex process that is operationally impractical and does little to advance pipeline safety. In fact, it may potentially have an adverse impact on pipeline safety as enormous resources are devoted to complying with these complicated measures in lieu of voluntary actions that have a proven result in advancing safety. As discussed in more detail below, AGA believes that PHMSA’s current proposed regulation continues to be exceptionally complicated, prescriptive, and generally infeasible.

PHMSA’s Complicated Approach to MAOP Verification and Material Verification Results in Regulatory Gaps and Inconsistencies

As an initial matter, as PHMSA considers the final rule, it is critical that PHMSA clearly distinguish between MAOP Determination (§192.619) and MAOP Verification (§192.624). PHMSA appears to use these terms interchangeably; however, AGA believes the connotation of each provides a completely different understanding of the actions being performed. Transmission and distribution pipelines have MAOPs that have been “determined” in accordance with applicable requirements at the time the pipeline was put into service, whether pursuant to Part 192, or prior to promulgation of the federal pipeline safety regulations in 1970 in accordance with industry consensus standards, state pipeline safety regulations, sound engineering principles, or company standards, policies and procedures. Therefore, AGA fundamentally believes that all in-service pipelines have already been subject to a valid MAOP “determination”. In contrast, the term MAOP “verification” conveys that for certain pipelines, PHMSA and industry recognize the need to conduct additional testing or assessments to confirm an MAOP. Using the term “MAOP determination” within §192.624(c): *Maximum allowable operating pressure verification: Onshore steel transmission pipelines*, incorrectly implies that existing pipelines have been operating without having a properly established MAOP.

In addition, AGA is concerned that PHMSA is treating the MAOP Verification requirements contained in the proposed §192.619(e) as incremental to existing MAOP Determination requirements. Specifically, AGA is concerned §192.619 or §192.624 do not expressly state that after an operator has complied with the proposed MAOP Verification requirements in §192.624, the operator has also satisfied the regulatory requirements for MAOP Determination in §192.619.

As an example, an operator of a transmission pipeline in a Class 3 location that was constructed after 1970 may be unable to locate the pipeline’s Subpart J pressure test records due to the company’s merger or acquisition activities. This pipeline would be subject to the proposed MAOP Verification requirements under proposed §192.624(a)(2)(ii) and the operator may choose to comply with the MAOP Verification requirements in §192.624 by using proposed Method 3: Engineering Critical Assessment. The Engineering Critical Assessment would satisfy the MAOP Verification requirements of proposed §192.624. However, when reviewing the requirements of MAOP Determination, the pipeline still would not have a record of its pressure test for use in determining MAOP under §192.619(a)(2). In summary, if an operator elects to use Method 2, Method 3, Method 5 or Method 6 (Alternative Technology) as approaches for MAOP Verification under the proposed §192.624(c), the codified regulatory text must explicitly state that the operator would not be required to have a pressure test record to comply with the requirements of §192.619(a)(2) and §192.517: *Records*.

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34 AGA maintains that any noncompliance would be with a record keeping provision, not with any provision of §192.619.
A similar concern arises related to PHMSA’s proposed Material Verification requirements, §192.607. As proposed, PHMSA would require pipeline operators to implement a prescriptive and burdensome Material Verification program when they lack records of material properties that have never been required by the current or prior regulations. Such a program is well outside the scope of Section 23 of the Pipeline Safety Act of 2011, which required only that operators verify whether their existing records reflected the physical and operational characteristics of specific categories of pipelines. Section 23 was silent on requiring testing to determine material properties. In addition, the proposed Material Verification program lacks any reference to or acknowledgement of MAOP determination. As a result, a pipeline that has an established MAOP documented through a subpart J pressure test, could still be subject to the proposed Material Verification requirements due to an operator’s inability to produce material records not previously required by the regulations. This disconnect would lead to a significant burden imposed on the pipeline industry with no valid safety concern.

Finally, PHMSA has stated in the preamble that this proposed rule provides methods for addressing insufficient records only for those pipelines that meet the applicability of §192.607, for Material Verification, and §192.624, for MAOP Verification. However, PHMSA states that pipelines that do not meet the applicability of these sections “would be required to comply with existing (more expensive) requirements for addressing the same issue.” See 81 Fed. Reg. 20814. Operators should be provided the flexibility to apply the methods prescribed for higher risk pipeline to lower risk pipelines. As PHMSA itself acknowledges, “[l]ocations outside HCAs and all Class 3 and 4 are by definition lower risk, meaning if incidents occur, the consequences are expected to be smaller than HCA and all Class 3 and 4 locations.” If PHMSA determines a method appropriate in higher risk areas, there is no valid justification for limiting an operator from applying this method in a lower risk location. Any other outcome would be inconsistent with the goal of effective and efficient pipeline safety regulations or PHMSA’s obligation to promulgate regulations that are reasonable and based on a reasoned determination that the benefits of a standard justify its costs.

AGA recognizes PHMSA’s concerns related to material and MAOP Verification and would like to offer an alternative approach to addressing the Congressional mandates and the intent of the NTSB recommendations. See Section III.A. of these comments for further details. The subsequent sections of these comments, Section IV.A.1 on MAOP Determination, Section IV.A.2 on Material Verification, and Section IV.A.3 on MAOP Verification are AGA’s attempts to outline specific technical and regulatory issues with PHMSA’s proposed language. If PHMSA does not redirect the final regulation towards a simpler approach, as AGA has offered, then AGA asks PHMSA to consider these technical and regulatory language revisions and refinements to those sections.

1. MAOP Determination

PHMSA is proposing to modify and add requirements within §192.619 Maximum allowable operating pressure: Steel or plastic pipelines. AGA refers to this section of pipeline safety regulations as “MAOP Determination” throughout these comments. Specifically, PHMSA is introducing new test pressure factors for

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35 PHMSA has not fully identified what existing regulatory requirements would apply to pipelines with related to incomplete or missing records; however, the one code section that PHMSA does reference, §192.107(b), in no way would require that an existing pipeline be excavated to confirm material properties as a result of missing or inadequate records. The obligation to maintain extensive material property documentation or MAOP documentation does not currently exist within the pipeline safety code. PHMSA’s suggestion is a misapplication of existing regulations to address what the agency perceives as inadequate records.
pipelines in Class 1 locations installed after the effective date of the rule, additional considerations for operators to take into account when determining MAOP under §192.619(a)(4), references to the proposed §192.624, and introduces a new record retention requirement for §192.619. PHMSA also introduces timeframes for the establishment of MAOPs for gathering lines that are newly subject to Part 192 in §192.619(a)(3).

In the introduction to this section, AGA has provided as context the evolution of MAOP Determination, both prior to the enactment of pipeline safety regulations and after. The ensuing comments specific to §192.619 are provided with this context established. AGA will provide comments on the following issues:

1. Clarification that the new requirements within §192.619(f) are applicable only to gas transmission pipelines.
2. The new record retention requirements implemented through the proposed §192.619(f) should not be retroactive and should be narrowed only to those records that are needed for MAOP Determination.
3. The confusion that results from referencing Material Verification, §192.607, in §192.619(a)(4).
4. The interaction between MAOP Determination and Verification, resulting from the §192.624 reference in §192.619(e).

(1) **Clarification that the new record requirements in §192.619 (f) are applicable only to gas transmission pipelines.**

AGA has significant concerns about the unintended application of these proposed changes to natural gas distribution pipelines. The impact of the Proposed Rule on distribution facilities are generally discussed in Section III.C of these comments; below, AGA clarifies the impact on distribution pipelines specific to the changes being proposed to §192.619.

AGA is not supportive of any proposed regulation that would elevate the record requirement to be maintained for the MAOP determination of distribution pipelines, as proposed under §192.619(f). PHMSA has stated in numerous public forums, including the DOT Pipeline Advisory Committee meeting held June 1-2, 2016 and the PHMSA webinar held June 8, 2016, that the scope of the proposed regulation is not meant to include natural gas distribution pipelines. On the contrary, the language in §192.619(f) states that “Operators must maintain all records necessary to establish and document the MAOP of each pipeline as long as the pipe or pipeline remains in service.” “Pipeline,” as stated here, would apply to any transmission, gathering or distribution pipeline subject to 49 C.F.R. Part 192. AGA strongly recommends that PHMSA revise the language in §192.619(f) to reflect their statements and clarify that the section is only applicable to on-shore steel transmission pipelines.

As discussed in Section III.C of these comments on Impacts to Distribution Pipelines, it is a well-established fact that gas distribution pipelines behave significantly different from gas transmission pipelines. This fact has been repeatedly underscored, including by PHMSA’s own report, “Integrity Management for Gas Distribution, Report of Phase 1 Investigations,” which recognized that distribution lines are much more likely to leak than rupture, and that the dominant cause of distribution incidents is excavation damage, with third party damage being the major contributor to these incidents. Distribution pipelines operate at hoop stress levels below 20% SMYS (typically significantly below 20% SMYS), well below the 30% SMYS level that is recognized by the Congressional mandate as a threshold demarcating higher risk and commonly associated with pipeline rupture.
In consideration of the lower pressure operating conditions associated with distribution pipelines, regulatory requirements are generally less prescriptive than requirements for transmission pipelines. Therefore, AGA urges PHMSA to provide clarity within the proposed regulation that these new MAOP record retention requirements are specific to gas transmission pipelines only by adding language to this effect in §192.619(f). If PHMSA intends to apply these requirements beyond gas transmission pipelines, then this modification should either be addressed in a separate rulemaking or the impact adequately accounted for within the PRIA. See Appendix A AGA’s suggested modifications to §192.619.

AGA strongly recommends that any language in the proposed regulation that would impact gas distribution pipelines, such as §192.619(f), be revised to provide clarification that the proposed regulations are applicable only to natural gas transmission pipelines.

(2) The new record retention requirements implemented through the Proposed Rule in §192.619(f) should not be retroactive and should be narrowed to only those records that are needed for MAOP Determination.

AGA is supportive of prospectively elevating the requirements for MAOP Determination records to be retained for transmission pipelines installed one year after the effective date of the rule. AGA believes the listed records within §192.619(f) need to be limited to only those records that an operator relies upon to establish the MAOP. The one-year interval prior to requirements going into effect is necessary in order to allow operators sufficient time to revise and implement policies, procedures, recordkeeping and training necessary to capture the required information. As discussed in Section III.E, AGA is supportive of applying a quality standard of “traceable, verifiable, and complete” prospectively on MAOP records for transmission pipelines. AGA believes that this position is consistent with the NTSB’s support for this section and expanding pipeline record requirements through a pipeline’s service life.

Limiting the application of this requirement to prospective MAOP determinations is consistent with PHMSA’s authority. PHMSA is prohibited from regulating existing pipelines with regard to “design, installation, construction, initial inspection, [and] initial testing.” See 49 U.S.C. §60104(b). Because the documentation of MAOP Determination would rely upon initial testing records, design, installation, and construction records, PHMSA is prohibited from promulgating regulations that would require the documentation of these activities for existing pipelines. Imposing a retroactive requirement to newly document aspects of an existing pipeline’s design, installation, construction or testing that would be used to document MAOP falls squarely within this prohibition.

PHMSA has not adequately justified its proposal to require documentation of MAOP records, either prospectively or retroactively. Section 23 of the Pipeline Safety Act of 2011 is silent on the requirement that operators document MAOP, either retroactively or prospectively, and is limited in scope to specific pipelines. PHMSA’s response to the Section 23 mandate is limited to requiring operators to verify whether existing records accurately reflect pipeline characteristics and confirm the established MAOP, and to promulgating regulations that MAOP be reconfirmed for pipelines with records insufficient to confirm the established MAOP or have not been previously tested. The Section 23 mandates also apply only to a specific set of pipelines, notably transmission

36 AGA notes that the exact seam type is not necessary to perform both MAOP determination.
37 National Transportation Safety Board Comments on Docket PHMSA-2011-0023 (June 6, 2016) at 6. AGA notes that the NTSB’s comments incorrectly reference §192.619(e) instead of §192.619(f).
38 This mandate has been fulfilled through operators’ submission of data to the Natural and Other Gas Transmission and Gathering Pipeline Systems Annual Report, Part Q.
pipelines in Class 3 and 4 locations and Class 1 and 2 HCAs with insufficient records, and transmission pipelines in HCAs operating at greater than 30% SMYS. Nowhere within these mandates is there an affirmative obligation to document, prospectively or retroactively, MAOP determination for all pipelines – transmission, distribution and gathering.

Furthermore, PHMSA has failed to consider the reasonableness, the appropriateness for the particular types of pipelines, the expected benefits or the expected costs of such a broadly applicable and detailed recordkeeping requirements. In fact, PHMSA’s sole justification appears to be reliance on Section 23, see PRIA at page 95, with no explanation of the intended benefits or purpose of the requirement. PHMSA explicitly states that is has not estimated the benefits of this requirement, see PRIA at page 128, despite its statutory authority to do so.

(3) The ultimate confusion that results from referencing Material Verification, §192.607, in §192.619(a)(4).

AGA understands PHMSA’s desire to provide additional clarity on the considerations that should be included in an operator’s analysis of the pipeline’s MAOP per §192.619(a)(4). However, AGA believes that by referencing §192.607 (Material Verification), which is applicable only to gas transmission pipelines in HCAs and Class 3 and 4 locations, PHMSA inadvertently expands the applicability of §192.607 to include all pipelines - both transmission and distribution. This is also discussed in Section IV.A.2 of these comments on Material Verification. AGA supports the addition of “material records” in the list of considerations, but reminds PHMSA that the existing “history of the segment” effectively covers concerns about what operators should consider when establishing MAOP. Therefore, AGA suggests striking the following language for §192.619(a)(4): “including material properties identified in accordance with §192.607.”

(4) Due to the lack of clarity from circular references between §192.619(e) and §192.624, PHMSA should delete the proposed language in §192.619(e).

As discussed in more detail below in AGA’s comments on §192.624, MAOP Verification, the requirements in §192.624 are standalone requirements that an on-shore steel transmission pipeline is subject to, supplemental to the requirements of MAOP Determination, §192.619. PHMSA’s proposed reference to §192.624 within §192.619 is unnecessary and incongruous. AGA believes that the proposed requirements under §192.619(e) should be deleted. As discussed in more detail below, §192.619(a) should instead be revised to make clear that any MAOP Verification Method conducted under §192.624 inherently satisfies the regulatory requirements for MAOP Determination within §192.619.

Based on the above comments, AGA’s suggested language to clarify §192.619 is below:

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

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

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

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

(ii) If the pipe is 12\(\frac{3}{4}\) inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

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

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

<table>
<thead>
<tr>
<th>Class location</th>
<th>Factors$^1$, segment—</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Installed before (Nov. 12, 1970)</td>
</tr>
<tr>
<td>1</td>
<td>1.1</td>
</tr>
<tr>
<td>2</td>
<td>1.25</td>
</tr>
<tr>
<td>3</td>
<td>1.4</td>
</tr>
<tr>
<td>4</td>
<td>1.4</td>
</tr>
</tbody>
</table>

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

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

<table>
<thead>
<tr>
<th>Pipeline segment</th>
<th>Pressure date</th>
<th>Test date</th>
</tr>
</thead>
</table>

45
— Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006 but before (insert effective date of the rule) — Onshore gathering line that first became subject to this part (other than §192.612) on or after (insert effective date of the rule) — Onshore transmission line that was a gathering line not subject to this part before March 15, 2006

<table>
<thead>
<tr>
<th>Type of Pipeline</th>
<th>Onshore Gathering Lines</th>
<th>Offshore Gathering Lines</th>
<th>All Other Pipelines</th>
</tr>
</thead>
<tbody>
<tr>
<td>First Became Subject</td>
<td>March 15, 2006, or date line becomes subject to this part, whichever is later</td>
<td>July 1, 1976</td>
<td>July 1, 1965</td>
</tr>
<tr>
<td>Date Line Becomes Subject to This Part</td>
<td>(Insert date that is one year after the effective date of the rule), or date line becomes subject to this part, whichever is later.</td>
<td>March 15, 2006, or date line becomes subject to this part, whichever is later.</td>
<td></td>
</tr>
</tbody>
</table>

(4) The pressure determined by the operator to be the maximum safe pressure after considering, material records including material properties identified in accordance with §192.607, and the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

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

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

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

1. **Method 1: Pressure Test** – Pressure test in accordance with §192.624(c)(1)(i) or spike hydrostatic pressure test in accordance with §192.624(c)(1)(ii), as applicable;
2. **Method 2: Pressure Reduction** – Reduction in pipeline maximum allowable operating pressure in accordance with §192.624(c)(2);
3. **Method 3: Engineering Critical Assessment** – Engineering assessment and analysis activities in accordance with §192.624(c)(3);
4. **Method 4: Pipe Replacement** – Replacement of the pipeline segment in accordance with §192.624(c)(4);
(5) **Method 5: Pressure Reduction for Segments with Small PIR and Diameter** - Reduction of maximum allowable operating pressure and other preventive measures for pipeline segments with small PIRs and diameters, in accordance with § 192.624(c)(5); or

(6) **Method 6: Alternative Technology** - Alternative procedure in accordance with § 192.624(c)(6).

(f) (e) For onshore steel transmission pipelines installed after [one year after effective date of rule], operators must maintain all records necessary to establish and document the established MAOP of each pipeline as long as the pipe or pipeline remains in service. Records that may establish the pipeline MAOP, include, but are not limited to, design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type and other related data. For onshore steel transmission pipeline installed after [one year after effective date of rule], records used to document the established MAOP must be reliable, traceable, verifiable, and complete.

2. Material Verification

**AGA Opposes Cumbersome, Retroactive New Material Verification Requirements in Proposed §192.607**

PHMSA is proposing a prescriptive, complicated and unnecessarily burdensome process for verifying specific physical characteristics of pipelines, fittings, valves, flanges, and components when operators lack reliable, traceable, verifiable, and complete records in HCAs and Class 3 or Class 4 locations. See 81 Fed. Reg. 20812; proposed §192.607.

As stated in other sections or our response, AGA does not believe it is appropriate to require that operators document and verify material properties of existing pipelines and various appurtenances above and beyond what was required by the regulations in place at the time the pipeline was put into service.

AGA recognizes PHMSA’s desire that operators maintain documentation or verify material characteristics used in calculating design pressure for MAOP as well as remaining strength calculations. AGA believes these activities can be accomplished safely without performing the requirements found within the proposed Material Verification requirements in §192.607.39

AGA maintains that pipelines with test records supporting at least a 1.25 MAOP pressure test have a valid MAOP. Where a pipeline has such a test record, the records verifying the MAOP through the design formula as prescribed in §192.619(a)(1) are duplicative and unnecessary for the purposes of validating an MAOP. For pipelines with a test record of at least 1.25 MAOP pressure test, AGA maintains that the MAOP is confirmed and there is no need to document material properties to verify the MAOP for these pipelines.

For remaining strength calculations, operators use supported, sound engineering judgments or conservative assumptions that functionally serve as safety factors when there are specific record gaps. AGA

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39 During the PHMSA Public Webinar on June 8, 2016 pertaining to this rulemaking, PHMSA referenced ASME B31.8S: *Managing System Integrity of Gas Pipelines* Table 4.2.1-1 “Data Elements for Prescriptive Pipeline Integrity Program” as another element in the justification for requiring the extensive list of material records prescribed in the proposed §192.607(c): *Material Documentation*. AGA believes this is a gross misapplication of a standard meant for integrity management and not MAOP Verification or remaining strength analysis. Data elements to be included in integrity management analysis are addressed in §192.917(b), which are discussed later in these comments in Section IV.E.3.
believes that these judgments or assumptions are sufficient to make conservative calculations and material verification is not necessary to perform the calculations. To AGA’s knowledge, there has never been a reportable incident resulting from an operator using inappropriate or non-conservative calculations or inputs to calculations. In AGA’s proposed edits, throughout the regulatory text, AGA encourages the allowance for supported engineering judgments or conservative assumptions whenever material records and §192.607 are referenced. AGA supports operators validating pipeline records that support remaining strength calculations through testing of pipelines that are replaced or removed from service. In the event that an operator determines there is a need to obtain a specific physical attribute for calculation of remaining strength, the operator can gather that information at the time that the pipeline is exposed for examination or repair. See Appendix A, sections §192.13, §192.485, §192.619, §192.624, §192.713, §192.929 and §192.933 for these recommended edits.

If PHMSA insists upon requiring a Material Verification process for pipelines in HCAs and Class 3 & 4 locations without traceable, verifiable, and complete material property records, AGA strongly urges the following changes which are detailed in these comments:

- PHMSA’s limited authority to prescribe the Material Verification Requirements for existing pipelines,
- Narrowing of the physical attributes to only those needed in MAOP determination and remaining strength calculations (i.e. Diameter, Wall Thickness, SMYS, and Seam Type),
- Providing performance based thresholds for operator defined material verification plans,
- Aligning the determined prescriptive requirements with current technological capabilities and methodologies,
- Allowing for new technology solutions,
- Ensuring consistency between §192.607 and the new record requirements within §192.67, §192.127 and §192.205, and
- Properly accounting for the impact of these new requirements within the PRIA.

**PHMSA’s Limited Authority to Prescribe Retroactive Material Documentation and Verification Requirements for Existing Pipelines**

PHMSA asserts that the new Material Verification requirements are needed to implement the Congressional mandate added in the Pipeline Safety Act of 2011, Section 23(a), which says:

(1) IN GENERAL.—The Secretary of Transportation shall require each owner or operator of a pipeline facility to conduct, not later than 6 months after the date of enactment of this section, a verification of the records of the owner or operator relating to the interstate and intrastate gas transmission pipelines of the owner or operator in class 3 and class 4 locations and class 1 and class 2 high-consequence areas.

(2) PURPOSE – The purpose of the verification shall be to ensure that the records accurately reflect the physical and operational characteristics of the pipelines described in paragraph (1) and confirm the established maximum allowable operating pressure of the pipeline.

See 81 Fed. Reg. 20812. However, PHMSA has incorrectly interpreted this mandate. Congress did not instruct PHMSA, in Section 23(a) or elsewhere in the Pipeline Safety Act of 2011, to retroactively require material property documentation for existing pipelines, or require the verification of material properties in the absence of such
records. Instead, Congress instructed operators to verify whether their existing records accurately reflected the physical and operational characteristics of a specific set of pipelines and report to PHMSA those pipelines with records insufficient to confirm the established MAOP. See 49 U.S.C. §60139(c). As PHMSA acknowledges, operators have submitted this information in their annual reports. See 81 Fed. Reg. 20812. Nowhere in this mandate does Congress require operators to retroactively create records that were not required to be created or maintained previously, nor conduct material verification on existing pipeline.

PHMSA’s proposed Material Verification requirements constitute a retroactive requirement that operators have documentation of material properties on pipelines already in service. As noted above, prior to 1970, there were no federal pipeline safety regulations. As pipeline safety regulations were issued, operators were required to collect and maintain specific data on their pipelines. But even under the current regulations, there is no obligation that operators maintain an extensive database of the physical characteristics associated with each pipeline segment. Therefore, requiring an operator to have such records is a retroactive requirement to document the design, installation, and construction of an existing pipeline. Such a requirement is expressly prohibited and outside of PHMSA’s authority: “A design, installation, construction, initial inspection, or initial testing standard does not apply to a pipeline facility existing when the standard is adopted.” See 49 U.S.C. §60104(b).

To the extent that the proposed Material Verification requirements impose prospective requirements on existing pipelines, the proposed requirements, as detailed below, are unnecessarily unreasonable and would be essentially impracticable to comply with. AGA’s comments below provide solutions that meet the intent of the proposed regulation in a feasible and reasonable manner.

Because PHMSA lacks authority under Section 23 of the 2011 Pipeline Safety Act to promulgate the proposed Material Verification requirements, PHMSA must act within the limitations on its general authority, including the obligation to consider the reasonableness of the standard, consider the costs and the benefits, and propose and issue only those standards supported by a reasoned determination that the benefits of the intended standard justify its costs. PHMSA has failed to act within these limitations. PHMSA’s justification for the proposed Material Verification requirements are rooted in Section 23 of the 2011 Pipeline Safety Act, and the purported need for additional regulations to implement Section 23 of that Act. See 81 Fed. Reg. 20812. As discussed above, Congress did not legislate material verification in Section 23. There is nothing linking the facts with PHMSA’s determination to propose the standards. In addition, PHMSA has not provided an explanation of how the proposed requirements would advance pipeline safety and the cost savings associated with the proposed Material Verification requirements are unsupported. As discussed in more detail within AGA’s comments on the PRIA in Section V, PHMSA is misapplying the current regulations. There is nothing in the current regulations that would obligate an operator to conduct material verification in the absence of records that were never required to be maintained.

Narrowing of the Physical Attributes

There are six variables within the design formula for steel pipe (§192.105): yield strength, nominal outside diameter, nominal wall thickness, design factor, longitudinal joint factor, and temperature derating factor. The design factor is determined through the Class Location of the pipeline and the temperature derating factor is associated with the operation of the pipeline. This leaves four physical material variables needed by operators to calculate the design pressure for MAOP Determination per §192.619(a)(1). AGA agrees that the operator must know the diameter of the pipeline to perform this calculation, however the yield strength, nominal wall thickness,
and longitudinal joint factor can either be determined through supported, sound engineering judgments or conservative assumptions can be used as allowed by 49 C.F.R. 192 (yield strength: §192.107; nominal wall thickness: §192.109; and longitudinal joint factor: §192.113). These are the same variables used in remaining strength calculations, with the addition of condition-specific information.

Sound engineering judgments can be made for all three of these physical characteristics, based on the myriad of institutional documents that an operator has available to support these engineering judgments, including: purchasing records, stock book records, construction documents, bills of material, operating records, company engineering standards, etc. However, PHMSA’s proposal implies that only a Mill Test Report (MTR), and all the information found within that report, can be used for determining a pipeline’s MAOP and remaining strength. The proposal further implies that the operator can only validate the pipeline’s yield strength if they know the grade (yield strength and ultimate tensile strength), chemical composition, Charpy v-notch toughness, manufacturing specification, etc. This is an overreach, as ultimate tensile strength and chemical composition are not necessary to perform remaining strength calculations or to calculate design pressure as discussed above. Furthermore, PHMSA has not provided a rationale of how these elements would contribute in determining the MAOP or contribute to the verification of the integrity of a pipeline.

AGA does agree that for pipelines where the grade of pipe is of an unknown origin, some chemical composition information may be useful for determining the pipe grade, depending upon the methodology used. In some methodologies, operators may need to know the carbon and manganese compositions in order to improve the confidence level of non-destructive testing techniques for yield strength and the operators will obtain this information as a part of their program. However, there are some technologies that do not need chemical composition to determine pipe grade. For example, the T.D. Williamson Positive Material Identification (PMI) methodology uses ball indentation and the ASME hardness and yield strength correlations do not need chemical composition to determine grade. AGA recommends the following code language for §192.607(d)(3)(iii).

At each excavation, tests for material properties must determine the material properties that are necessary to calculate MAOP and for use in remaining strength calculations.

Any requirement to retroactively obtain ultimate tensile strength and chemical composition is unnecessarily and unreasonably burdensome, has questionable value, and detracts from the ultimate goal of pipeline safety by diverting valuable resources away from other risk-reduction efforts. An operator will use known information to make an informed decision on a strength value used for yield strength, and the operator will often err on the side of estimating a yield strength value that is more conservative than the actual value. In listing grade (yield strength and ultimate tensile strength) within the proposed code requirements under §192.607(c), PHMSA fails to recognize that material grade cannot currently be identified with non-destructive evaluations (NDE) on pipeline components such as flanges and valves. PHMSA is also requiring that all valves with weld ends must have material documentation for weld end and bevel condition, which may not be available for early vintage valves and cannot be determined in the field after the valve has been welded. This requirement is not only unreasonable, it is impossible. It is reasonable for an operator to confirm the material rating and capture one of the following: the applicable standard to which the component was manufactured, the manufacturing rating, or the pressure rating.

Likewise, AGA supports the inclusion of longitudinal joint factor determination in the necessary physical characteristics for material verification. However, identifying the exact seam type is not necessary to perform
MAOP determination and remaining strength calculations. Additionally, PHMSA fails to recognize in the PRIA that there are no single, validated, non-destructive testing (NDT) technologies currently available to determine seam type. A combination of visual examination, radiography and in-situ metallographic examinations are needed.

Each of these concerns would be addressed by making the changes suggested in AGA’s proposed modifications to §192.607, found in Appendix A of these comments.

Providing Performance Based Thresholds

- **Defining Sections of Pipelines in Material Documentation Plan**
  
  §192.607(d)(3)(i): PHMSA requires that operators “define a separate population of undocumented or inadequately documented pipeline segment for each unique combination of attributes.” This exercise is unnecessarily burdensome. It should only be necessary for operators to determine which pipelines have unknown physical attributes for the purpose of MAOP determination and remaining strength calculations.

  To address PHMSA’s safety goal with less burden, AGA urges PHMSA to revise the proposed text as follows:

  The operator must define identify each pipeline a population of with an undocumented or inadequately documented pipeline segment attribute or set of attributes required for MAOP determination and remaining strength calculations. for each unique combination of the following attributes: wall thicknesses (within 10 percent of the smallest wall thickness in the population), grade, manufacturing process, pipe manufacturing dates (within a two year interval) and construction dates (within a two year interval).

  §192.607(d)(3)(iii): In this section, PHMSA prescriptively lists all of the material properties that an operator should determine at an excavation. The list is extensive and overly burdensome and in some cases ends up being duplicative of the efforts operators are performing while completing Pipe Condition Reports per §192.459. To reduce the burden while still achieving PHMSA’s pipeline safety goal, AGA recommends that PHMSA simplify this list to reference the minimum material properties that are necessary to calculate MAOP and remaining strength. This change would put the responsibility on the operator to ensure they have obtained all necessary physical attributes necessary to perform these calculations. AGA urges PHMSA to revise this section as follows:

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

- **Confidence Levels for Non-Destructive Tests**
§192.607(d)(3)(iv): AGA opposes PHMSA’s proposal that methods, tools, procedures, and techniques for non-destructive tests must be independently validated by subject matter experts in metallurgy and fracture mechanics. Many pipeline operators have subject matter experts on staff that can confirm test results are accounting for measurement accuracy and uncertainty and are achieving the same confidence level as destructive test solutions. PHMSA should allow operators to deploy solutions to meet the needs that their Material Verification plan has defined. Additionally, there are procedures for calculating strength from hardness, such as ASME CRTD Vol 91 report, that are significantly conservative and below the 10% confidence level from the measure destructive test value outlined in PHMSA’s proposal. PHMSA introduction of prescriptive confidence levels prevents operators from being even more conservative than the methodology suggests. AGA proposes the following changes to meet the intent of the proposal in a reasonable fashion:

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

• The Minimum Number of Test Locations at Each Excavation or Above-Ground Location

§192.607(d)(3)(v): As discussed in the sections above, AGA proposes a performance based approach to the determination for the minimum number of test locations at each excavation or above-ground location. PHMSA has provided no technical justification for the frequency in their proposal. The prescriptive frequency proposed may exceed that required for statistically based confidence levels. Operators should determine the number of test locations based upon the number of excavations needed to statistically prove the physical characteristics of the pipeline. Below is a solution on how PHMSA can meet the intent of its proposal in a way that better improves pipeline safety:

The minimum number of test locations at each excavation or above-ground location is based on the number of excavations determined to be necessary by the operator through statistical analysis the number of joints of line pipe exposed, as follows:

(A) 10 joints or less: one set of tests for each joint.
(B) 11 to 100 joints: one set of tests for each five joints, but not less than 10 sets of tests.
(C) Over 100 joints: one set of tests for each 10 joints, but not less than 20 sets of tests.

• Inconsistent Material Test Results

§192.607(d)(3)(viii): AGA opposes PHMSA’s proposal for prescriptive requirements associated with inconsistent material properties. As written, PHMSA’s proposal forces operators to add 1.5 times the number of excavations whenever an inconsistent data point is identified, even if that data point is more conservative (e.g. greater strength or greater wall thickness) than the current assumption. Additionally, there is no statistical basis for PHMSA’s proposed frequency of 1.5 times the number of excavations. The unintended consequence for this prescriptive requirement is that operators would be encouraged to
assume they have no records and therefore will never find an inconsistent test result, versus using all information they have available to them and making an informed judgment for the material property. AGA urges PHMSA to revise this provision as follows:

If the results of all tests conducted in accordance with paragraphs (i) and (ii) verify that unknown material properties are consistent with all available information on each population pipeline or are more conservative than current assumptions (such as: thicker walled pipe, smaller diameter, or higher grade), then no additional excavations are necessary. However, if the test results identify line pipe with properties that are not consistent as conservative as the current with existing assumptions expectations based on all available information for each population pipeline, then the operator must modify their Material Documentation Program testing frequency to address these inconsistencies. perform tests at additional excavations. The minimum number of excavations that must be tested depends on the number of inconsistencies observed between as-found tests and available operator records, in accordance with the table below:

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

- **Use of Material Test Results**
§192.607(d)(5): While AGA understands intent behind the inclusion of this requirement in the proposal, AGA believes additional clarification is required. In cases where an operator is already using a conservative material assumption, such as 24,000 psi for yield strength as provided for in §192.107, the operator should be permitted to increase the assumed material grade to the actual material grade which is determined and verified through the Material Verification program once an adequate number of data points has been established. The provision should be revised as follows for clarity:

The material properties determined from the destructive or non-destructive tests required by this section cannot be used to raise the original grade or specification of the material, unless the current MAOP is unknown and is based on an assumed yield strength of 24 ksi in accordance with §192.107(b)(2).

**Aligning with Current Technologies & Methodologies**
Throughout this new proposed section, PHMSA has introduced very prescriptive testing requirements with no technical justification provided for the frequency and location of these tests on the pipeline. In Appendix
A of these comments, AGA provides suggested edits to 49 C.F.R. §192.607 to better align with existing technologies and industry research. AGA provides detailed justification for AGA’s suggested edits below:

- **Minimum Number of Excavations**
  §192.607(d)(3)(ii): The minimum number of excavations should be determined by the operator in the operator’s Material Verification plan and through statistical analysis. AGA recommends that PHMSA allow this performance-based sampling methodology instead of PHMSA’s proposed prescriptive frequency. The allowance for a statistical analysis to determine the sampling frequency puts the responsibility on the operator to determine the necessary number of excavations and to provide justification. AGA urges PHMSA to revise the provision as follows:

  For each pipeline population identified according to (i) above, the minimum number of excavations at which line pipe must be tested to verify pipeline material properties is determined in accordance with either the lesser of the following (A) or (B).

  (A) The lesser of (i) or (ii); or
  i. 150 excavations; or
  ii. If the segment is less than 150 miles, a number of excavations equal to the population’s pipeline mileage (i.e., one set of properties per mile), rounded up to the nearest whole number. The mileage for this calculation is the cumulative mileage of pipeline segments in the population without reliable, traceable, verifiable, and complete material documentation.
  iii. Assessments must be proportionally spaced throughout the pipeline segment. Each length of the pipeline segment equal to 10 percent of the total length must contain 10 percent of the total number of required excavations, e.g., a 200 mile population would require 15 excavations for each 20 miles.

  (B) Alternatively, an operator may determine the number of excavations through statistical analysis.

- **Locations & Frequencies of Non-Destructive Tests**
  §192.607(d)(3)(vi): AGA believes the location of non-destructive tests around the circumference of the pipe, as suggested in the proposal, is dated and not representative of current technological capabilities. There is no technical justification to support the requirement to complete a minimum of 20 readings at each location. In fact, this extreme frequency actually has a negative impact on pipeline safety as it will require operators to remove even more of the pipe coating, which increases the risk of coating holidays and external corrosion. As mentioned in the previous comment section, making the requirement performance based versus prescriptive allows operators and service providers to establish the necessary frequency without being constrained by a static requirement that fails to account for changes in technology and that is unnecessarily arbitrary. AGA suggests the following requirement for non-destructive test frequency and location:

  For non-destructive tests, at each test location, a set of material properties tests must be conducted in accordance with the number appropriate to achieve the accuracy requirements established in (iv) above in accordance with a qualified testing procedure at a minimum of five
places in each circumferential quadrant of the pipe for a minimum total of 20 test readings at each pipe cylinder location.

- **Locations & Frequencies of Destructive Tests**

$\S 192.607(d)(3)(vii)$: AGA is fundamentally opposed to requiring operators to remove a cylinder of pipe to perform destructive tests and then perform a material test at each of the four quadrants on the cylinder that is removed. This requirement is unnecessarily costly, and has a negative impact on pipeline safety since the integrity of the pipeline has now been compromised and a new joint of pipe will need to be welded onto the pipe to replace the removed cylinder. In addition, the testing goes beyond manufacturing standards. Pipeline operators have historically conducted material testing at one location on the pipe. For example, in manufacturing standards such as API 5L: *American Petroleum Institute 5L Specification for Line Pipe*, ASTM A106: *Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service*, and ASTM A53: *Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless*, the standard requires one base metal tensile test and one cross seam tensile test. AGA is not aware of a single pipe specification that requires multiple base metal tensile tests for pipe samples as PHMSA has proposed.

AGA does support testing of pipe that is removed from service for other reasons and the testing of coupon sized samples for destructive testing for material properties. In fact, in GTI Report #20568: *Establishment of Yield Strength Using Sub-sized Samples without Gas Line Shutdown* the authors state that “the mini, full-wall specimens were found to be superior to the currently specified full-size tensile specimens in every respect.” Operators have used these standards and reports as guidance in their proactive Material Verification programs. Therefore, PHMSA’s prescriptive proposal could potentially make these technically supported historical material tests invalid.

In addition, depending on the physical parameters associated with an operator’s system, removing a single cylinder from an in-service pipeline for testing may cost many tens or even hundreds of thousands of dollars which is not accounted for in the PRIA. Operators should be permitted to use existing coupon testing technology on one coupon taken from the exposed pipe for material testing. AGA suggests the following changes to the requirements for destructive tests to account for current manufacturing standards and technologies:

*For destructive tests, at each test location, a set of materials property tests must be conducted in accordance with an applicable manufacturing specification, on each circumferential quadrant of a test pipe cylinder removed from each location, for a minimum total of four tests at each location.*

**Allowing for New Technologies**

Technology providers are constantly striving to develop new solutions for the determination and verification of material properties for pipelines. Currently there is no allowance for inclusion of these new solutions within $\S 192.607$. For example, due to the overly prescriptive nature of the requirements within $\S 192.607(d)$, PHMSA has essentially prevented the use of the new ILI solutions that are currently being tested,

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and in some cases, deployed. AGA does not believe this was PHMSA’s intent and suggests the addition of §192.607(d)(3)(x):

In the event that an operator determines another technology, such as in-line inspection, is capable of meeting the confidence levels specified in §192.607(d)(3)(iv), the Material Documentation Plan should be revised to reflect the use of this other technology. The technology must be able to capture a statistically significant quantity of data for each pipeline for which material verification is being performed.

This new section would negate the need for the proposed §192.607(d)(6). Additionally, it should be noted that the proposed language within §192.607(d)(6) is very confusing as it refers to §192.624(e).

Ensuring Consistency

AGA encourages consistency between the material documentation required within §192.607(c) and those which are listed within the prospective documentation requirements in §192.67 Records: Materials, §192.127 Records: Pipe design, and §192.205 Records: Pipeline components. Inconsistencies between these documentation requirements could create irrational scenarios where operators are meeting the new documentation requirements but find themselves still required to perform the Material Verification requirements under §192.607, which AGA believes is not PHMSA’s intent.

Accounting for Impact Accurately

In the PRIA, PHMSA attempts to justify the extraordinary costs associated with compliance with §192.607 by pointing to the existing code requirements for Qualification of Pipe within Appendix B for 49 C.F.R. Part 192. See 81 Fed. Reg. 20812, 14. PHMSA even states that §192.607 is a cost savings as it provides an alternative to the code requirements per §192.107(b), which references Appendix B and states that for pipe where tensile properties are not known, they may be established by performing tensile tests as set forth in API Specification 5L, such as 1 test for 10 lengths or less, etc. What PHMSA fails to acknowledge both in the Proposed Rule and in the PRIA is that this requirement was not codified for application to in-service buried pipelines. Instead, it is in an appendix to code that addresses how to handle pipe material that is readily accessible and not yet installed. §192.107 is located within Subpart C, Pipe Design, section that can only be applied to new pipelines and does not apply retroactively. Given this context, there is simply no support that §192.107 would require an operator to perform tensile tests on an existing, buried pipeline because records of material properties, not required by the regulations, were not available. PHMSA’s attempt to use this basis for a “cost savings” for operators is misleading and inappropriate. The PRIA should be revised to accurately account for this entirely new requirement for operators to obtain material records.

It should be noted that the only place in the PRIA where the costs for Material Verification are mentioned is within the section on the costs to perform repairs, Table 3-63: Range of Typical Repair Costs. It is unclear where, if at all, the Material Verification costs related to material documentation, plan creation, and revisions, testing and other costs are incorporated into the overall impact assessment.

AGA fully asserts that the true costs for implementing PHMSA’s proposals are vastly under represented. When an operator performs “Material Verification” as proposed by PHMSA, they will be required to perform countless in-the-ditch nondestructive tests in 20 locations on the pipe or will be required to cut an entire cylinder out of the exposed pipe for destructive sampling. The costs to complete this work, even neglecting the costs to run bypasses to maintain service and the installation of replacement pipe, far outweigh PHMSA’s estimates of
$2,000 and $4,000. It is perplexing that PHMSA then states that the cost to perform a Material Verification would be $75,000, as “the process is very similar to doing a repair via pipe replacement.”

AGA members report the costs to cut-out a cylinder sample when the pipeline is already exposed for other purposes can cost on average $80,000 accounting for both destructive testing and non-destructive testing for material properties. A further discussion of these issues is provided in Section V: Preliminary Regulatory Impact Assessment in these comments.

Below is AGA’s full proposal for modifying the proposed §192.607 in a way that meets PHMSA’s intent, improves pipeline safety, while reducing the extraordinary cost and burden of this provision:

§ 192.607 Verification of Pipeline Material: Onshore steel transmission pipelines.
(a) **Applicable Locations.** Each operator must follow the requirements of paragraphs (b) through (d) of this section for each segment of onshore, steel, gas transmission pipeline installed before [insert the effective date of the rule] that does not have reliable, traceable, verifiable, and complete material documentation records for line pipe, valves, flanges, and components and meets any of the following conditions:
   (2) The pipeline is located in a High Consequence Area as defined in § 192.903; or
   (3) The pipeline is located in a class 3 or class 4 location
(b) **Material Documentation Plan.** Each operator must prepare a material documentation plan to implement all actions required by this section by [insert date that is 180 days after the effective date of the rule].
(c) **Material Documentation.** Each operator must have reliable, traceable, verifiable, and complete records documenting the material documentation records for line pipe, valves, flanges, and components to establish MAOP where supportable, sound engineering judgments cannot be made, including:
   (1) For line pipe and fittings, records must document diameter, wall thickness, specified minimum yield strength, grade (yield strength and ultimate tensile strength), chemical composition, and pipe class for longitudinal joint factor determination, per §192.113 seam type, coating type, and manufacturing specification.
   (2) For valves, records must document either one of the following: the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating and grade. For valves with pipe weld ends, records must document the valve material grade and weld end bevel condition to ensure compatibility with pipe end conditions;
   (3) For flanges, records must document either one of the following: the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating and grade, and the material grade and weld end bevel condition to ensure compatibility with pipe end conditions;
   (4) For components, records must document the applicable standards to which the component was manufactured to ensure pressure rating compatibility;
(d) **Verification of Material Properties.** For any material documentation records for line pipe, valves, flanges, and components specified in paragraph (c) of this section that are not available, the operator must take the following actions to determine and verify the physical characteristics. While the operator is performing these actions, supportable, sound engineering judgments are permitted to be utilized.
   (1) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for line pipe at all above ground locations.
(2) Develop and implement procedures for conducting destructive tests, examinations, and assessments for buried line pipe at all excavations associated with replacements or relocations of pipe segments that are removed from service.

(3) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for buried line pipe at all excavations associated with anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, or any other reason for which the pipe segment is exposed, except for segments exposed during excavation activities that are in compliance with §192.614, until completion of the minimum number of excavations as follows.

   number of excavations determined to be necessary by the operator through statistical analysis.

   (i) The operator must define identify each pipeline a population of with an undocumented or inadequately documented pipeline segment attribute required for MAOP determination and remaining strength calculations. for each unique combination of the following attributes: wall thicknesses (within 10 percent of the smallest wall thickness in the population), grade, manufacturing process, pipe manufacturing dates (within a two year interval) and construction dates (within a two year interval).

   (ii) For each pipeline population identified according to (i) above, the minimum number of excavations at which line pipe must be tested to verify pipeline material properties is determined in accordance with either the lesser of the following (A) or (B).

      (A) The lesser of (i) or (ii); or

      i. 150 excavations; or

      ii. If the segment is less than 150 miles, a number of excavations equal to the population’s pipeline mileage (i.e., one set of properties per mile), rounded up to the nearest whole number. The mileage for this calculation is the cumulative mileage of pipeline segments in the population without reliable, traceable, verifiable, and complete material documentation.

      iii. Assessments must be proportionally spaced throughout the pipeline segment. Each length of the pipeline segment equal to 10 percent of the total length must contain 10 percent of the total number of required excavations, e.g. a 200 mile population would require 15 excavations for each 20 miles.

      (B) Alternatively, an operator may determine the number of excavations through statistical analysis.

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

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

(v) The minimum number of test locations at each excavation or above-ground location is based on the number of excavations determined to be necessary by the operator through statistical analysis the number of joints of line pipe exposed, as follows:

(A) 10 joints or less: one set of tests for each joint,
(B) 11 to 100 joints: one set of tests for each five joints, but not less than 10 sets of tests.
(C) Over 100 joints: one set of tests for each 10 joints, but not less than 20 sets of tests.

(vi) For non-destructive tests, at each test location, a set of material properties tests must be conducted in accordance with the number appropriate to achieve the accuracy requirements established in (iv) above in accordance with a qualified testing procedure at a minimum of five places in each circumferential quadrant of the pipe for a minimum total of 20 test readings at each pipe cylinder location.

(vii) For destructive tests, at each test location, a set of materials properties tests must be conducted in accordance with an applicable manufacturing specification on each circumferential quadrant of a test pipe cylinder removed from each location, for a minimum total of four tests at each location.

(viii) If the results of all tests conducted in accordance with paragraphs (i) and (ii) verify that unknown material properties are consistent with all available information on each population pipeline or are more conservative than current assumptions (such as: thicker walled pipe, smaller diameter, or higher grade), then no additional excavations are necessary. However, if the test results identify line pipe with properties that are not consistent as conservative as the current assumptions expectations based on all available information for each population pipeline, then the operator must modify their Material Documentation Program testing frequency to address these inconsistencies. perform tests at additional excavations. The minimum number of excavations that must be tested depends on the number of inconsistencies observed between as found tests and available operator records, in accordance with the table below:

<table>
<thead>
<tr>
<th>Number of Excavations with Inconsistency Between Test Results and Existing Expectations Based on All Available Information for each Population</th>
<th>Minimum Number of Total Required Excavations for Population. The lesser of:</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>150 (or pipeline mileage)</td>
</tr>
<tr>
<td>1</td>
<td>225 (or pipeline mileage times 1.5)</td>
</tr>
<tr>
<td>2</td>
<td>300 (or pipeline mileage times 2)</td>
</tr>
<tr>
<td>&gt;2</td>
<td>350 or pipeline mileage times 2.3</td>
</tr>
</tbody>
</table>
(ix) The tests conducted for a single excavation according to the requirements of §192.607(d)(3)(iii) through (vii) above count as one sample under the sampling requirements of §192.607(d)(3)(i), (ii), and (viii).

(x) In the event that an operator determines another technology, such as in-line inspection, is capable of meeting the confidence levels specified in §192.607(d)(3)(iv), the Material Documentation Plan should be revised to reflect the use of this other technology. The technology must still be able to capture a statistically significant quantity of data for each pipeline for which material verification is being performed.

(4) For mainline pipeline components other than line pipe, the operator must develop and implement procedures for establishing and documenting one of the following: the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating. The ANSI rating and material grade (to assure compatibility with pipe ends).

   (i) Materials in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, operator piping, or cross-connections with isolation valves from the mainline pipeline are not required to be tested for chemical and mechanical properties.

   (ii) Verification of mainline material properties is required for non-line pipe components, including but not limited to, valves, flanges, fittings, fabricated assemblies, and other pressure retaining components appurtenances that are:
        (A) 2-inch nominal diameter and larger, or
        (B) Material grades greater than 42,000 psi (X-42), or
        (C) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

   (iii) Procedures for establishing material properties for non-line pipe components where records are inadequate must be based upon documented manufacturing specifications. Where specifications are not known, usage of manufacturer’s stamped or tagged material pressure ratings and material type may be used to establish pressure rating. The operator must document the basis of the material properties established using such procedures.

(5) The material properties determined from the destructive or non-destructive tests required by this section cannot be used to raise the original grade or specification of the material, unless the current MAOP is unknown and is based on an assumed yield strength of 24 ksi in accordance with §192.107(b)(2), which must be based upon the applicable standard referenced in §192.7.

(6) If conditions make material verification by the above methods impracticable or if the operator chooses to use “other technology” or “new technology” (alternative technical evaluation process plan), the operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph §192.624(e) of this section. The operator must submit the alternative technical evaluation process plan to the Associate Administrator of Pipeline Safety with the notification and must obtain a “no objection letter” from the Associate Administrator of Pipeline Safety prior to usage of an alternative evaluation process.

3. MAOP Verification
AGA continues to be supportive of a pipeline safety regulation requiring the one-time MAOP Verification for certain natural gas transmission pipelines through methods that provide regulatory certainty and are technically justified. Specifically, AGA maintains its support for MAOP Verification consistent with the Pipeline Safety Act of 2011:

(1) Reconfirming MAOP for gas transmission pipelines in Class 3 and 4 locations and Class 1 and 2 HCAs that have insufficient records to confirm MAOP, 49 U.S.C. §60139(c); and
(2) Testing to confirm the material strength of previously untested gas transmission pipelines in HCAs that operate at a pressure above 30% SMYS using safety testing methodologies, including pressure testing, ILI and other alternative methods determined to be of equal or greater effectiveness, 49 U.S.C. §60139(d).

PHMSA has proposed to require MAOP Verification for higher priority pipelines that have experienced specific in-service incidents, do not have RTVC records of a post-construction Subpart J pressure test, or are currently using the “grandfather clause”, §192.619(c), for MAOP determination. The proposed MAOP Verification would be completed through the use of one of six different methodologies, which would also include a requirement to perform fracture mechanics modeling on pipelines that “may be susceptible to cracks and crack-like defects.”

AGA is extremely concerned that PHMSA is continuing in a direction that is inconsistent with the Congressional mandates contained in the 2011 Pipeline Safety Act of 2011. PHMSA’s proposed requirements go well outside the scope of the Congressional mandates and fail to provide operators with reasonable and practicable MAOP Verification methods that meet the requirements of the Congressional mandate. PHMSA has provided inadequate explanation, justification, or analysis to support its proposed requirements.

Through these comments, AGA offers PHMSA suggested changes that AGA believes would achieve the same level of safety, but in a clear and simple manner. AGA’s comments focus on the expansive scope and practicability of the proposed MAOP Verification requirements, and highlight the following items:

- The need to amend the final rule to clearly reflect that applying a method under §192.624 inherently resolves any potential gaps in compliance with §192.619 for that pipeline;
- The applicability of PHMSA’s MAOP Verification is inconsistent with the Congressional Mandates;
- The necessity for PHMSA to only prescribe straightforward and technically justifiable actions under each of the MAOP Verification methods, rather than imposing overly prescriptive requirements which have no corresponding benefit in enhancing safety;
- The need to provide clarification on record retention requirements;
- The need to provide reasonable deadlines for completing MAOP Verification; and
- The requirement for PHMSA to revise the impact assessment to represent realistic costs associated with the adoption of rule requirements.
MAOP Verification is an enormous undertaking that will require the support of PHMSA, operators, and state regulatory bodies to coordinate several key challenges, such as skilled workforce and contractor availability, competition for material availability (pipe, valves, fittings, etc.), prolonged permitting timeframes, customer service reliability, outage management, and methane emissions from replacing, testing or re-testing pipelines. As PHMSA moves forward with finalizing the MAOP Verification methods, PHMSA must recognize the significant role that state governing bodies will have in funding these actions. Congress recognized that this coordination is critical and specifically instructed PHMSA to coordinate the timing for the completion of MAOP testing for previously untested transmission pipelines with FERC and state regulators. See 49 U.S.C. §60139(d)(3). In addition, when continuity of gas service could be affected, PHMSA is also to coordinate with these regulators. Id. at §60104(d)(1).

An effort of this magnitude cannot be accomplished with a one-size-fits-all federal safety regulation. AGA commends PHMSA’s proposed MAOP Verification Methods to the extent that it provides operators with flexibility in addressing the unique and diverse conditions in which pipelines operate. It is critical, however, that the proposed §192.624 MAOP Verification Methods are straightforward and convey clearly defined and direct regulatory requirements. PHMSA should eliminate from within the MAOP Verification methods overly-prescriptive and rigid requirements that are superfluous and unnecessary to achieve PHMSA’s goal and will instead drain limited resources. The proposed MAOP Verification methods should reflect existing code language, including actions taken by operators under Subpart O regulations, and allow operators to undertake assessments that are well integrated with the timing of work already being conducted to comply with the totality of existing pipeline safety regulations.

The applicability of PHMSA’s Proposed MAOP Verification

PHMSA has proposed that its MAOP Verification requirements apply to three separate groups of transmissions pipeline segments:

1. Pipeline segments that have experienced a reportable in-service incident due to an original manufacturing- or construction-related defect (§192.624(a)(1));
2. Pipelines segments with insufficient pressure test records (§192.624(a)(2)); and
3. Pipeline segments relying upon §192.619(c), the “grandfather clause” to determine their MAOP (§192.624(a)(3)).

The following comments detail AGA’s concerns with each of the three groups of pipelines to which the proposed MAOP Verification requirements would be applicable and provide solutions that meet the intent of the rule.

1. Pipelines That Have Experienced an In-Service Incident (§192.624(a)(1))

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

PHMSA has proposed to require MAOP Verification for certain transmission pipelines that have experienced a reportable in-service incident, as defined in §191.3, since the most recent Subpart J pressure test
due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect...” See 49 C.F.R. §191.624(a)(1). As drafted, the proposed MAOP Verification would apply retroactively, to pipelines that have experienced such an incident in the past, and prospectively, to future incidents.

One of the concerns with proposed §192.624(a)(1) is incidents that may occur in the future. The proposed MAOP Verification in §192.624 does not address how the completion plan and completion dates required by §192.624(b) would apply to pipelines that experience the future failure and are now subject to proposed §192.624(a)(1), or for pipelines that are not currently located in an MCA but may be in the future. For example, if an incident occurs 16 years after the effective date of a final rule, it is unclear how long an operator would have to complete the MAOP Verification requirements. In addition, the interaction between §192.624 and §192.917(e)(3) is not clear. AGA is concerned that PHMSA has not thought through how prospective incidents would be addressed through §192.624 and the interaction with the proposed requirements in §192.917(e)(3). See AGA’s comments in Section IV.E.3 on §192.917 and in Section IV.D on the proposed Subpart Q.

As noted above, AGA has significant concerns with the application of the proposed MAOP Verification to this set of pipelines. However, more fundamentally, PHMSA offers no reasoning, analysis or justification for the inclusion of these pipelines in the MAOP Verification requirements. PHMSA’s rationale for including these pipelines appears related to the NTSB’s recommendation that that manufacturing- and construction-related defects can only be considered stable if a pipeline has since been subjected to a hydrostatic pressure test of at least 1.25 times MAOP (NTSB P-11-15), which AGA believes is addressed through the proposed requirements in §192.917(e)(3). The inclusion of these pipelines in §192.624(a)(3) appears to be redundant.

To address this issue, AGA recommends that PHMSA remove the applicability in §192.624(a)(1) and address this concern through §192.917(e)(3) and §192.1119, which is proposed by AGA in Section IV.D of these comments. This would provide clarity for operators and regulators the required actions for pipelines that have had a reportable in-service incident due to manufacturing and construction related defects both in the past and in the future. As described in AGA’s comments on the proposed Subpart Q, AGA recommends that PHMSA limit the requirement for historical incidents to only those which there are publicly available records from PHMSA, as operators are under no obligation to maintain records of incidents that would detail the specificity of the incident to determine whether the incident and pipeline is subject to the proposed requirements.

It should also be noted that there is an absence in PHMSA’s description of the proposed requirements and the PRIA of any analysis or justification supporting inclusion of these pipeline segments, including no estimation of impacted miles or intended benefits. Even if adopting an NTSB recommendation did provide PHMSA with the authority, the proposed requirements depart from the NTSB recommendation. They are narrower in scope in that they only apply to specified pipelines that have had an incident, and a pressure test of 1.25 is not required, but merely an option for compliance.41

2. Pipelines Without Pressure Test Records (192.624(a)(2))

41 Although, in connection with the §192.917(e)(3) proposed requirements, it appears that a pressure test would be the only way an operator could satisfy both requirements.
Pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment, including, but not limited to, records required by §192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline is located in one of the following locations:

PHMSA is proposing to require MAOP Verification for transmission lines located in HCAs and Class 3 and Class 4 locations, where the operator does not have reliable, traceable, verifiable and complete pressure test records. See §192.624(a)(2). AGA supports the scope of pipelines included within §192.624(a)(2), to the extent that it is consistent with the Congressional Mandate to reconfirm MAOP for pipelines within Class 3 and 4 locations and Class 1 and 2 HCAs with insufficient records to confirm MAOP. See 49 U.S.C. §60139(c).

However, AGA is concerned that as drafted, this section could inadvertently apply to those pipelines that have had no requirement to maintain a pressure test record. Specifically, §192.624(a)(2) should be revised to clarify that it applies only to those transmission pipelines in HCAs and Class 3 and 4 locations that were constructed and put into operation since the adoption of the federal pipeline safety regulations in 1970. Otherwise, §192.624(a)(2) would apply to those pipelines put into service prior to the implementation of federal regulations, to which the requirement to maintain a pressure test record do not apply. Excluding these pipelines from §192.624(a)(2) is consistent with PHMSA’s proposed MAOP Verification requirements to include specific pipelines that rely upon §192.619(c), the “Grandfather Clause,” to determine MAOP, as well as the Congressional mandate that PHMSA separately address these pipelines, See 49 U.S.C. §6.139(d).

In addition, consistent with AGA’s comments on PHMSA’s proposed use of the phrase “reliable, traceable, verifiable and complete” in Section III.E, PHMSA should delete this reference as it applies to existing pipelines. Under the current regulations, there is no requirement that a pressure test record be “reliable, traceable, verifiable, or complete.” By retroactively raising the standard of quality applied to records, PHMSA is retroactively altering the standard that applied to past actions by operators of transmission pipelines. Specifically, PHMSA would be retroactively regulating the initial testing of existing pipelines. Congress expressly prohibited PHMSA from enacting such a standard. See 49 U.S.C. §60104(b). Operators have reviewed their records related to MAOP determinations for Class 3 and 4 locations and Class 1 and 2 HCAs pursuant to PHMSA’s May 7, 2012 Advisory Bulletin on Verification of Records describing the “traceable, verifiable, and complete” standard as well as PHMSA’s subsequent clarification that a single pressure test record satisfied this requirement. AGA members will continue to follow this approach for verifying MAOP, but strongly feel that a codified RTVC standard should not be applied retroactively.

3. Pre-1970 Pipelines Operating Under the “Grandfather Clause” (§192.624(a)(3))

The pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) of this subpart before [insert effective date of rule] and is located in one of the following areas:

Under Section 23(d) of the 2011 Pipeline Safety Act, Congress mandated that the Secretary of the Department of Transportation issue regulations for the industry to conduct testing to confirm the material

43 Letter from John A. Gale, Director, PHMSA, to Christina Sames, Vice President, American Gas Association (July 31, 2012).
strength of previously untested gas transmission pipelines in HCAs that operate at a pressure above 30% SMYS, using safety methodologies which include pressure testing, in-line inspections, and other alternative methods determined to be of equal or greater effectiveness. It is understood that Section 23(d) was addressing pipelines put in service prior to the pipeline safety regulations going into effect that rely upon §192.619(c), the “grandfather clause,” to determine their MAOP.

AGA supports the Congressional mandate in Section 23(d). However, the proposed applicability for MAOP Verification for previously untested transmission pipelines under §192.624(a)(3) goes significantly beyond the Congressional mandate. Instead of limiting the confirmation of material strength of previously untested transmission pipelines in HCAs operating at a pressure above 30% SMYS, PHMSA has proposed to require MAOP Verification for all transmission pipelines in HCAs, Class 3 and Class 4 locations, and MCAs for pipelines that are capable of accommodating in-line inspection tools (i.e. “smart pigs”). PHMSA provides no justification for departing from Congress’ clear intent other than that this expansion is intended to address the NTSB recommendations and to provide increased safety in areas where a pipeline rupture would have a significant impact on the public or the environment. See 81 Fed. Reg. 20814. PHMSA offers no justification independent from the NTSB recommendation, no explanation linking how the MAOP Verification methods would increase safety in the areas beyond those specifically mandated by Congress, and no explanation on why this is necessary. Furthermore, there is no reasoned justification that the intended benefits of expanding the MAOP Verification requirements would justify the costs. Ultimately, PHMSA has provided no reasoned justification for departing from the Congressional mandate, or imposing the MAOP Verification requirements on these pipelines.

AGA appreciates that PHMSA has not recommended wholesale adoption of the NTSB Recommendation to delete the grandfather clause and subject these pipes to a hydrostatic pressure that incorporates a spike test. AGA respects the NTSB and its investigative expertise; however, the NTSB openly stated that it is not their role to write regulations or operate pipelines. NTSB also stated they are open to alternative approaches to their recommendations. Although AGA disagrees with PHMSA’s approach to go beyond the Congressional mandate, AGA supports PHMSA’s approach to the repeal of the grandfather clause. As discussed in Section IV.G, AGA believes a spike test is appropriate for very specific applications and could negatively impact the safety of a line if used inappropriately. AGA appreciates PHMSA’s recognition that there are better regulatory alternatives than adopting the NTSB Recommendation verbatim.

**PHMSA’s Proposed MAOP Verification Requirements Are Inconsistent with the Congressional Mandates**

AGA has consistently supported MAOP Verification as outlined in the 2011 Pipeline Safety Act. However, the Proposed Rule would require MAOP Verification for a much broader scope of pipelines, and therefore significantly more mileage of affected transmission pipelines. The result is that the Proposed Rule would require operators to address the MAOP Verification of pipelines that were of specific concern to Congress simultaneously with pipelines that were not of Congressional concern and that represent a much lower risk to public safety. This creates a conflict in priorities and will necessarily mean that the pipelines of explicit concern to Congress and high relative risk will not be addressed as soon as they could be if the scope of the Proposed Rule were limited to what PHMSA was prescribed by Congress. This result is in direct contradiction to Congress’ will.

Section 23(c) of the Pipeline Safety Act instructed PHMSA to require that MAOP reconfirmation for pipelines in Class 3 and 4 locations and Class 1 and 2 HCA as “expeditiously as economically feasible.” See 49 U.S.C.
Expanding the scope of the pipelines subject to MAOP Verification requirements necessarily means that those pipelines of concern to Congress will not be addressed as expeditiously as feasible.

Along similar lines, Section 23(d) of the Pipeline Safety Act instructed PHMSA that regulations for the testing of previously untested natural gas transmission pipelines located in HCAs and operating at pressure greater than 30% SMYS shall take into account “potential consequences to public safety and the environment and that minimize costs and service disruptions.” Id. at §60139(d)(3). Including pipelines that are beyond Congress’ instruction fails to minimize costs and service disruptions.

PHMSA’s proposed MAOP Verification methods are also inconsistent with the Congressional mandates. For pipelines that have insufficient records to confirm the established MAOP, PHMSA’s proposed MAOP Verification requirements cannot be said to address these pipelines as “expeditiously as economically feasible.” See 49 U.S.C. §60139(c)(1)(A). As described in more detail in AGA’s comments on the PRIA in Section V, PHMSA fails to provide cost estimates for the majority of the proposed MAOP Verification methods. PHMSA provides no cost estimate for the engineering critical assessment or the hydrostatic spike pressure test. For the pressure reductions, pipe replacement and alternative technology, PHMSA suggests that these are “extreme measures” that operators would likely not use. See PRIA, page 33. As currently proposed, many of AGA’s members would be required to conduct pipe replacement. By failing to provide these cost estimates, there is no suggestion that PHMSA took this mandate into consideration or that PHMSA’s proposal has complied with the Congressional mandate to “minimize costs.” Id. at §60139(d)(3). Moreover, PHMSA’s inclusion of methods that PHMSA suggests are “extreme measures” that operators would likely not use cannot be said to be reasonable or justified and is, by definition, arbitrary and capricious.

Because applicability within the MAOP Verification program is in part predicated on the requirement to have a pressure test record (§192.624(a)(2)), operators are in essence forced to use the pressure test as a verification method, to the exclusion of the other methods. If a pipeline operator chooses any of the five other methodologies within of §192.624(c) besides Method 1: Pressure test, the pipeline in question will continue to meet the applicability requirements of §192.624(a)(2) for not having a pressure test record. Eliminating this flexibility is in direct violation of the Section 23 Congressional mandates. For pipelines with insufficient records to confirm MAOP, limiting MAOP Verification to pressure testing eliminates other less costly measures that can be implemented in a timelier manner. This is in direct violation that PHMSA require the MAOPs for these pipelines be reconfirmed as “expeditiously ad economically feasible.” See 49 U.S.C. §60139(c)(1)(A).

There is a similar concern for pipelines relying on the “grandfather clause” that are subject to §192.624(a)(3). These pipelines were put into service prior to the development of the federal safety standards in 1970 and rely on the “Grandfather Clause” to support their MAOP. As stated previously, prior to 1970 there were no federal standards to document or maintain records related to the post-construction pressure test. In other words, these pipelines were not required to have a “subpart J” pressure test or to keep records of this test. As a result, these pipelines will also be subject to the proposed MAOP Verification requirements under §192.624(a)(2). For the pre-regulation pipelines, if a pipeline operator chooses any of the five other methodologies within of §192.624(c) besides Method 1: Pressure test, the pipeline in question will continue to meet the applicability requirements of §192.624(a)(2) for not having a pressure test record. In practical terms, this results in all “grandfathered pipelines” subject to §192.624(a)(3) being forced to perform a pressure test or to replace the pipe and conduct a post-construction pressure test.
Requiring “grandfathered pipelines” to rely upon the pressure test method for MAOP Verification is contrary to the Congressional mandate and inconsistent with PHMSA’s own PRIA. Congress specifically instructed PHMSA to consider the use of ILI technology and other alternative technologies determined to be of equal or greater effectiveness than pressure testing. See 49 U.S.C. §60139(d)(3). PHMSA has determined that the methodologies proposed in addition to pressure testing “would provide equal or greater effectiveness as a pressure test.” See 81 Fed. Reg. 20813. By eliminating these methods as compliance options, PHMSA’s Proposed Rule is inconsistent with and contrary to Congress’ clear statements in Section 23.

Not only is the limitation of methods inconsistent with the Congressional mandates, it also is inconsistent with PHMSA’s own statements in the preamble that purport to justify and explain its proposed MAOP Verification requirements. PHMSA goes to great lengths to describe the flexibility afforded by the Proposal by allowing operators to select from a range of methods, as well as the flexibility in allowing pipelines of small diameter and PIR to use alternative pressure reductions. These statements are inconsistent with the regulatory text that would eliminate the flexibility and require the use of a pressure test.

Finally, Congress mandated in Section 23(d) that previously untested transmission pipelines located in HCAs and operating at a pressure greater than 30% SMYS have the pipeline’s MAOP confirmed within a timeframe that takes into account potential consequences to public safety and the environment and that minimize costs and service disruption. This timeframe is to be developed in consultation with FERC and State regulations. See 49 U.S.C. §60139(d)(3). As noted above, a MAOP Verification program of this magnitude is a significant undertaking that affects many different regulatory agencies, including FERC and state regulators, as service is impacted. Despite Congress’ clear acknowledgement of the required coordination for such an undertaking, PHMSA has provided no record of its coordination with the regulators or justification for why such coordination was not necessary.

PHMSA makes broad conclusory statements in the PRIA that the proposed MAOP Verification requirements would establish timeframes that take into account potential consequences to public safety and the environment and that minimize costs and service disruptions. See PRIA, page 33. PHMSA has provided no support for this statement. Moreover, as noted above, the clear impact and effect of the Proposed Rule demonstrates that it is inconsistent with the Congressional mandates.

For these reasons, AGA strongly encourages PHMSA to limit the scope of the proposed MAOP Verification requirements to those pipelines that were the subject of the Congressional mandates as well as pipelines which are found to exhibit manufacturing-related and construction-related defects. The following language includes AGA’s proposed revisions to §192.624(a):

(a) Applicable Locations: ...
   (1) The pipeline segment has experienced a reportable in-service incident as defined in §191.3 since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including seam cracking, girth weld cracking, selective seam weld corrosion, or stress corrosion cracking and the pipeline segment is located in one of the following locations:
      (i) A high consequence area as defined in §192.903;
      (ii) A class 3 or class 4 location; or
(iii) — A moderate consequence area as defined in § 192.3 if can accommodate inspection by means of instrumented inline inspection tools (i.e., “smart pigs”).

(1) For pipelines not relying on 192.619(c) to determine MAOP, pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment are incomplete or unavailable, including, but not limited to, records required by § 192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline is located in one of the following locations:
   (i) A high consequence area as defined in § 192.903; or
   (ii) A class 3 or class 4 location

(2) The pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) of this subpart before [insert effective date of rule], operates at greater than 30% SMYS and is located in one of the following locations:
   (i) A high consequence area as defined in § 192.903;
   (ii) A class 3 or class 4 location;
   (iii) A moderate consequence area as defined in § 192.3 if the pipeline segment can accommodate inspection by means of instrumented inline inspection tools (i.e., “smart pigs”).

**MAOP Verification Methods Should be Straightforward & Technically Justified**

PHMSA has proposed six different methods by which operators could verify MAOP. As noted above, given the magnitude of MAOP Verification, it is critical that all methods proposed be viable, technically justified, and provide regulatory certainty. AGA maintains its position that MAOP Verification methods should be simple and straightforward. For each method, nothing incremental should be imposed on the operator to have to perform, unless it is technically based and necessary to the process of verifying the MAOP. In addition, PHMSA should clarify the distinction between MAOP Determination and MAOP Verification. This clarification should confirm the fact that MAOP Verification, like MAOP Determination, is a one-time requirement for specifically defined transmission pipelines, and that only one method is required to verify MAOP.

AGA strongly opposes the convoluted and prescriptive requirements within §192.624(d) Fracture Mechanics. See Section IV.A.3.a of these comments for further discussion on the Fracture Mechanics Modeling Section of the Proposed Rule, including a recommendation on its appropriate applicably and a simplification of the requirements.

Finally, AGA notes that Congress required PHMSA to consider MAOP Verification methods that were of equal or greater effectiveness as a pressure test. PHMSA makes the conclusory statement that its proposed methods meet this requirement. See 81 Fed. Reg. 20813, but provides no justification, support, or elaboration on the assessment methods it considered.

Below is AGA’s proposed wording for the beginning of §192.624 (a) and §192.624(c) to clarify that MAOP Verification is a onetime verification and that only one method is needed for this verification.

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44 The only exception to this foundation is if the pipeline becomes newly subject to the applicability of MAOP Verification due to a new in-service incident caused by a manufacturing, construction, installation, or fabrication related defect, or a cracking related defect that occurred in certain specified locations, or a subsequent lost MAOP record sometime in the future.
§192.624: Maximum allowable operating pressure verification: Onshore steel transmission pipelines.

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

(c) Maximum Allowable Operating Pressure Determination–Verification. The operator of a pipeline segment meeting the criteria in paragraph (a) above must establish verify its maximum allowable operating pressure using one of the following methods:

Method 1: Pressure Test (§192.624(c)(1))

AGA believes that Method 1: Pressure test is a methodology that many operators will choose for MAOP Verification. However, PHMSA has taken a very simple, well-established, straightforward methodology and made it incredibly complex. A Subpart J pressure test is the methodology used to determine MAOP under §192.619(a)(2). Subpart J provides different requirements and specifications for pressure tests based on the type of pipe being tested. However, as proposed under a Method 1 pressure test, an operator must perform a pressure test in accordance with §192.505(c), which provides the test duration for a pressure test on a steel pipe intended to operate at or above 30% SMYS. PHMSA has provided no justification for specifically referring to §192.505(c), which eliminates the viable pressure test options for pipelines operating less than 30% SMYS, facility piping, or fabricated assemblies. With a general reference to Subpart J, the rule would avoid inadvertently requiring operators to apply the wrong pressure testing methodology for the piece of the system being addressed. In 2015, 196 U.S. onshore natural gas transmission operators reported that 46,668 miles, representing 24.4% of the total reported 191,049 miles of intrastate and interstate transmission pipelines, operate at less than 30% SMYS and would be subject to the proposed MAOP Verification requirements. These pipelines should be permitted to use the viable, well-established pressure test requirements within Subpart J. PHMSA should not attempt to apply stringent new pressure testing requirements on pipelines that are “verifying” their MAOP above and beyond those methodologies used to “establish” MAOP. AGA strongly recommends that PHMSA simply reference testing in accordance with Subpart J for Method 1.

AGA has significant concerns with the proposed definitions of Legacy pipe and Legacy construction techniques in §192.3 and referenced in §192.624(c)(1), as well as the requirement to subject these types of pipelines to a spike pressure test. Fundamentally, the rule is proposing to require operators to perform pressure tests on a subset of legacy pipelines for durations that represent a higher level of risk than is necessary to identify any potential critical defects. AGA has offered alternatives to these terms in AGA’s proposed modifications below. This suggestion is further detailed in Section IV.H of these comments.

Also, as discussed above, AGA asserts that it is not appropriate for PHMSA to include such an expansive list of cracks and crack-like defects, and should not make the list comprehensive. As an example, AGA also does not support the inclusion of “hard spots” in the list of cracks or crack-like defects. Hard spot is a term that lends itself to judgment and there are no criteria which would help an operator to identify a hard spot on a pipeline.

The Proposed Rule uses the clause “but not limited to” which further leads to ambiguity and regulatory uncertainty on whether an operator is required to perform a spike test in circumstance beyond what is already noted in §192.624(c)(1)(ii). A spike test is a very specialized practice should be used in a very narrow set of conditions to identify the presence of critical flaws that can lead to a rupture of the pipe. As such, it is incumbent
upon the code language to be explicit regarding when a spike test is to be performed and what such a test entails. PHMSA presents no technical basis to suggest that additional circumstances may exist where spike testing is required, beyond the specific examples provided in the Proposed Rule.

AGA thereby suggests the following revisions to §192.624(c)(1):

1. **Method 1: Pressure test.**
   
   (i) Perform a pressure test in accordance with §192.505(c) Subpart J of this Part. The maximum allowable operating pressure will be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or §192.620(a)(2)(ii).
   
   (ii) If the pipeline segment includes legacy pipe or was constructed using legacy construction techniques or the pipeline pipe with a longitudinal joint factor less than 1.0, as defined in §192.113, was manufactured by a process no longer accepted by industry standards, was constructed using construction techniques or practices no longer acceptable for new construction under part 192, has experienced an incident, as defined by §191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking, that was not otherwise addressed by the operator, then the operator must perform a spike pressure test in accordance with §192.506. The maximum allowable operating pressure will be equal to the test pressure specified in §192.506(c) divided by the greater of 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or §192.620(a)(2)(ii).
   
   (iii) If the operator has reason to believe any pipeline segment may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph (d) of this section.

2. **Method 2: Pressure Reduction (§192.624(c)(2))**

   Proposed Method 2 would allow operators to reduce the existing, established MAOP to satisfy the MAOP Verification requirements. AGA strongly agrees that a pressure reduction is a technical method for validating MAOP since it essentially represents a pressure test that was conducted while the pipe was in-service. Absent an incident determined to have been caused by a construction or material related defect and a determination that the pipeline segment has been poorly maintained since its initial construction, there is no technical reason to require a Method 2 Pressure Reduction based on the maximum operating pressure during an 18-month period simply due to the fact that the pipeline was not operated at a higher pressure than PHMSA’s proposed timeframe. At a minimum, such safe operation effectively demonstrates that the pipeline segment is capable of continuously operating at the full maximum allowable operating pressure due to an operator’s prudent operation of the pipeline.

   If PHMSA chooses to maintain the Method 2 approach within the Proposed Rule, AGA firmly believes that 18 months is a much too narrow time frame for consideration. AGA reminds PHMSA of the intent behind MAOP Verification for pipelines that meet the applicable of proposed §192.624(a)(2) and §192.624(a)(3). Arguably these
pipelines only meet the applicability of this section due to a lack of pressure test or complete material records, not due to their unsafe operation. AGA views PHMSA’s concerns as a compliance concern, not a pipeline safety concern. Therefore, AGA proposes that PHMSA allow operators to search their operating records for the highest actual sustained pressure reached for 8 hours during a continuous 30-day history. There should be no limitation on when this pressure was achieved, whether 18-months or 20-years. The pipeline has proven to safely operate at these pressures for many years.

On the contrary, AGA suggests that PHMSA revise the proposed requirement to be more conservative for those pipelines that have had a reportable in-service incident since its most recent subpart J pressure test, due to an original manufacturing or construction-related defect. AGA suggests that the pressure reduction be taken from the operating pressure at the time of the incident. This would apply the appropriate margin of safety and is further discussed in AGA’s comments on Risk Assessments & Risk Models, and Subpart Q.

If PHMSA insists upon keeping a time frame, in order for this methodology to be viable, the time frame needs to be significantly widened from 18-months and the “evaluation window” needs to be a sliding timeframe. Operators need the flexibility to operate through multiple winter heating seasons and summer power generation supply cycles to have a more comprehensive view of the highest operating pressure that could be seen on their system due to actual operating conditions. If PHMSA maintains a timeframe approach, AGA suggests expanding the timeframe for the highest actual operating pressure sustained by the pipeline to five years prior to the effective date of the rule in order to allow operators a more comprehensive view of this “highest actual operating pressure” under normal operating conditions.

Additionally, as proposed, operators have 8 years to perform actions on 50% of their pipelines and 15 years to perform actions on the remainder of the applicable pipelines. If an operator works over those 15 years to ensure adequate capacity to their system, prior to taking a pressure reduction via Method 2 on their pipeline, they should not be required to take a pressure reduction off of an operating pressure that occurred some 15+ years in the past. The regulation in §192.624(c)(2) must be re-written to clarify that the pressure reduction is taken from the immediate past 18-months or 5-years from the time the pressure reduction is contemplated, which may actually be several years after the rule’s effective date. Tying the baseline pressure to the effective date of the rule is completely arbitrary when evaluating the merits of these actions on pipeline safety.

In addition, if an operator has been pro-active and voluntarily elected to reduce a pipeline’s MAOP during the time period from the promulgation of the Gas Pipeline Integrity Management Regulation (Subpart Q) on December 17, 2003 until the effective date of the Rule, the voluntary reduction in MAOP should be considered as a Pressure Reduction in the new MAOP as determined under §192.624(c)(2) Method 2. This fundamental principle is critical so that operators who have already reduced MAOP on pipe segments in an effort to be pro-active are not penalized by having to take further unnecessary reductions in MAOP. (In many instances, further reductions are not even possible if the pipeline is to continue serving its existing load.)

Finally, PHMSA should eliminate the explicit reference for the potential to uprating a pipeline under Subpart K. By providing this reference in some, but not all, of the MAOP Verification methods, the regulations could be interpreted that uprating pursuant to Subpart K may not be a future option for some pipes. If a pipeline meets the requirements of Subpart K for uprating, future uprating is obviously permissible regardless of which MAOP Verification method is used.
In summary:

1. If an operator elects to verify a pipeline’s MAOP using §192.624(c)(2) Method 2: Pressure Reduction, the new MAOP should be based either on the pipeline’s operating pressure at the time of the incident, if PHMSA maintains §192.624(a)(1), or the highest documented pressure on the pipeline, divided by 1.25 or the applicable class location factor defined in §192.619(a)(ii) or §192.620(a)(2)(ii).

2. If an operator has voluntarily reduced the pipeline pressure due to pending pipeline safety regulations or for an integrity management assessment, the operator should not be required to further reduce the pipeline pressure to meet the intent of §192.624(c)(2).

3. Regardless of the baseline pressure or the timeframe, the regulatory language needs to allow for the pressure reduction to be taken at any point during the allowable program window (currently proposed as 15 years) that the operator is performing the MAOP Verification. Therefore, the text needs to allow the operator to reduce the pressure under Method 2 based on recent pressures, not those that may have occurred immediately prior to the effective date of the rule.

4. AGA’s comments on Fracture Mechanics Modeling are captured in Section IV.A.3.a of these comments.

AGA proposes the following changes to the regulatory language in §192.624(c)(2) to capture the first two summary items above:

2. Method 2: Pressure Reduction - The pipeline maximum allowable operating pressure will be no greater than the pressure described in §192.620(c)(2)(i). The highest actual operating pressure sustained by the pipeline during the 18 months preceding [insert effective date of rule] must be used as the highest actual sustained operating pressure. The value used as the highest actual sustained operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest pressure value for the entire segment or using the operating pressure gradient (i.e., the location-specific operating pressure at each location).

   (i) Baseline pressure determination:

   (A) For pipelines that have experienced a reportable in-service incident due to an original manufacturing-related defect, a construction-, installation- or fabrication-related defect the pipeline maximum allowable operating pressure will be no greater than the actual operating pressure at the time of the reportable in-service incident divided by the greater of 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

   (B) For pipelines that meet the applicability of §192.624(a)(2) and §192.624(a)(3) the pipeline maximum allowable operating pressure will be no greater than the highest documented operating pressure sustained by the pipeline divided by 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or §192.620(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period.
(ii) Where the pipeline segment has had a class location change in accordance with § 192.611 and pipe material and pressure test records are not available, the operator must reduce the pipeline segment MAOP as follows:
   (A) For segments where a class location changed from 1 to 2, from 2 to 3, or from 3 to 4, reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding [insert effective date of rule], divided by 1.39 for class 1 to 2, 1.67 for class 2 to 3, and 2.00 for class 3 to 4.
   (B) For segments where a class location changed from 1 to 3, reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding [insert effective date of rule], divided by 2.00.

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

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

(v) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor, the operator must notify PHMSA in accordance with paragraph (e) of this section no later than seven calendar days after establishing the reduced maximum allowable operating pressure. The notification must include the following details:
   (A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in § 192.624(c)(2);
   (B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with paragraph (d) of this section;
   (C) Justification that establishing maximum allowable operating pressure by another method allowed by this section is impractical;
   (D) Justification that the reduced maximum allowable operating pressure determined by the operator is safe based on analysis of the condition of the pipeline segment, including material records, material properties verified in accordance § 192.607, and the history of the segment, particularly known corrosion and leakage, the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned.
   (E) Planned duration for operating at the requested maximum allowable operating pressure, long term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts in metallurgy and fracture mechanics.
Any reductions in MAOP voluntarily initiated by the operator from December 31, 2003 until the date that the operator elects to verify MAOP using Method 2 shall be considered as a Pressure Reduction conducted under §192.624(c)(2).

**Method 3: Engineering Critical Assessment (§192.624(c)(3))**

PHMSA has proposed to allow operators to verify MAOP through an Engineering Critical Assessment (ECA), which would include an in-line inspection (ILI). See proposed §192.624(c)(3). As detailed below, the proposed ECA option is extremely convoluted and would require operators to consider information that they do not currently possess (and is the reason for which they are going through the MAOP Verification process). AGA strongly encourages PHMSA to significantly revise the ECA method and instead provide a separate in-line inspection MAOP Verification method. See AGA’s comments on the new proposed method in the section titled "Method 7: In-Line Inspection in-lieu of Hydrostatic Pressure Testing."

The proposed ECA would require that operators consider a broad spectrum of information, related to material documentation, pipeline assessment, and cracks and crack-like defects. AGA reminds PHMSA that pipelines become subject to the proposed MAOP Verification requirements because they do not have a pressure test record (§192.624(a)(2)) or relied upon the grandfather clause for MAOP determination and were not subject to the federal testing requirements (§192.624(a)(3)). It is extremely unlikely that pipes meeting these criteria would have the documentation necessary to perform the required ECA analyses. Moreover, the prescriptive requirements necessary to meet the ECA standard are impracticable, if not, impossible to achieve.

The proposed ILI component of the ECA is illogical and inconsistent with the Proposed Rule. First, if a pipeline has a valid pressure test, it is not required to perform ILI as part of the ECA. See proposed §192.624(c)(3)(ii). If a pipeline had a valid pressure test under Subpart J or proposed §192.624(c)(1), there would be no reason for a pipeline to go through the ECA process to satisfy the MAOP Verification requirements. Second, PHMSA has provided that in lieu of ECA, an operator can use “other technology” if it is validated by an SME in metallurgy and fracture mechanics. Aside from the fact that confusing and convoluted requirements make these provisions infeasible, the operator can only proceed if they were to receive a “no objection” letter from PHMSA. AGA does not agree that PHMSA should be the gatekeeper of technology, as discussed in more detail below. It is clear that PHMSA does not understand the business aspect and required planning that go into purchasing and/or contracting for the use of these tools. Without providing a timeframe for a “no objection letter,” PHMSA ignores the fact that operators need regulatory certainty. Without this certainty, the “other technology” option is essentially an impracticable option. Finally, in PHMSA proposed specifications for ILI tools, PHMSA notes that results should be consistent with “the required corresponding hydrostatic test pressure for the segment being evaluated.” See proposed §192.624(c)(3)(iii)(E). AGA notes that there is no generally required hydrostatic test required for these segments, only a certain subset of pipelines that choose to use a pressure test and meet the requirements of §192.624(c)(1)(ii).

In AGA’s comments on the draft Integrity Verification Process, AGA was unable to provide substantive comment on an Engineering Critical Assessment (ECA) as PHMSA had provided no details on what this process would entail. However, AGA asserted that PHMSA must recognize the distinction between MAOP Verification and integrity management. Based on the Proposed Rule, it is apparent that PHMSA continues to confuse integrity management with MAOP Verification. Many of the elements within the ECA methodology are in fact integral
elements within a robust integrity management program, including evaluating past assessment method results, and analyzing metal loss defects, cracks and crack-like defects, all of which are already elements of Subpart O.

AGA encourages PHMSA to consider the alternate ECA proposal supplied by INGAA in their comments and supports their comments on this topic.

Method 4: Pipe Replacement – Replace the pipeline segment (§192.624(c)(4))
AGA has no comments on this methodology.

Method 5: Pressure Reduction for Segments with Small PIR and Diameter (§192.624(c)(5))
AGA commends PHMSA for providing a method that is intended to provide an additional option for transmission pipelines which are of lower relative risk based upon their low operating stress and smaller impact radius calculation. This demarcation at 30 percent SMYS is consistent with the Pipeline Safety Act of 2011, where Congress specifically requested regulations to facilitate assessment of HCA pipelines operating “at a pressure greater than 30 percent of specified minimum yield strength.” The 30% SMYS demarcation is also consistent with several industry studies which have investigated the boundary for leak vs. rupture whenever a pipeline fails due to a material condition, such as Battelle’s “Integrity Characteristics of Vintage Pipelines” (2005) and GTI’s “Leak vs Rupture Considerations for Steel Low-Stress Pipelines” (2013).

It is critical for PHMSA to understand the unique challenges faced by AGA member companies in conducting assessments on low stress transmission pipelines which are often completely embedded into the distribution network. It is more difficult to pressure test or perform ILI assessments on these pipelines compared to rural transmission pipelines, which have a tendency to have a higher operating stress. Throughout the country, transmission pipelines operated by LDCs directly serve subdivisions, industrial parks, businesses, small cities and villages. Many of these pipelines are one-way feeds and the single source of gas, requiring temporary bypasses or use of multiple LNG/CNG trailers to be used to maintain gas service. In addition, many of these lines operate at lower pressures, have multiple valves and lateral lines, and include bends that make it difficult or impossible to remove water from the line if a hydrostatic test is conducted. Operators will need to identify viable alternatives regarding how and when to perform the in-service testing or replacement of these low stress lines in order to meet regulations. Often these low stress lines are defined as transmission lines due to the functional transmission line definition or state rules and not due to their operation at high pressures or transporting large volumes of natural gas. In such situations, they present a lower risk and should be prioritized as such.

Given the distinction between these low stress pipelines and the transmission pipelines that Congress was specifically concerned with and that represent a higher risk to public safety, there are justifiable reasons for providing these pipelines with flexibility in their MAOP Verification. In fact, many of the principles of integrity management could be used to address PHMSA’s concerns with MAOP Verification for these pipes. AGA believes that it is critical that PHMSA provide a workable solution for MAOP Verification for these pipelines.

PHMSA’s proposed pressure reduction for small PIR and diameter pipes would require a pressure reduction and prescriptive Preventative and Mitigative (P&M) measures. However, AGA does not believe it is reasonable for the rule to require both a pressure reduction and the implementation of a list of P&M measures, as captured in §192.624(c)(5)(iii) through (viii). Fundamentally, Method 5 should reflect either a 10% pressure reduction, or the implementation of additional P&M actions that are feasible and practical, but not both. As
proposed, these “low risk” pipelines would be subjected to additional requirements significantly beyond existing regulatory requirements and also beyond the requirements for those pipelines that are utilizing Method 2 (Pressure Reduction). AGA does not believe that this is PHMSA’s intent, nor has PHMSA provided adequate justification for imposing these requirements. By creating a methodology that allows the operator to directly address threats to their system, PHMSA creates consistency between this methodology and the fundamental pipeline safety benefits realized through §192.941: What is a low stress reassessment? AGA also suggests the same baseline pressures to be utilized as proposed in Method 2: Pressure Reductions.

Below is AGA’s suggestions for how Method 5 can be revised to address the above concerns:

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

(i) Reduce the pipeline maximum allowable operating pressure to no greater than the pressure described in §192.624(c)(5)(i)(A), (B), or (C) during 18 months preceding [insert effective date of rule]. The reduced maximum allowable operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire segment or the operating pressure gradient (i.e., the location specific operating pressure at each location).

(A) For pipelines that have experienced a reportable in-service incident due to an original manufacturing-related defect, a construction-, installation- or fabrication-related defect the pipeline maximum allowable operating pressure will be no greater than the actual operating pressure at the time of the reportable in-service incident divided by 1.1.

(B) For pipelines that meet the applicability of §192.624(a)(2) and §192.624(a)(3) the pipeline maximum allowable operating pressure will be no greater than the highest documented operating pressure sustained by the pipeline divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of eight hours during one continuous 30-day period.

(C) Any reductions in MAOP voluntarily initiated by the operator from December 31, 2003 until the date that the operator elects to verify MAOP using Method 2 shall be considered as a Pressure Reduction initiated under 192.624(c)(5); or

(ii) Perform the following additional actions to ensure the safety of the pipeline.

(A) Conduct external corrosion direct assessment in accordance with § 192.925, and internal corrosion direct assessment in accordance with § 192.927;

(B) Develop and implement procedures for conducting non-destructive tests, examinations, and assessments for cracks and crack-like defects, including but not limited to stress corrosion cracking, selective seam weld corrosion, girth weld cracks, and seam defects, for pipe at all excavations associated with anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, or any other reason for which the pipe segment is exposed, except for segments exposed during excavation activities that are in compliance with § 192.614;
(C) Conduct monthly patrols in Class 1 and 2 locations, at an interval not to exceed 45 days; weekly patrols in Class 3 locations not to exceed 10 days; and semi-weekly patrols in Class 4 locations, at an interval not to exceed six days, in accordance with § 192.705;

(D) Conduct monthly, instrumented leakage surveys in Class 1 and 2 locations, at intervals not to exceed 45 days; weekly leakage surveys in Class 3 locations at intervals not to exceed 10 days; and semi-weekly leakage surveys in Class 4 locations, at intervals not to exceed six days, in accordance with § 192.706; and

(E) Odorize gas transported in the segment, in accordance with § 192.625;

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

(iii) Under Method 5, future uprating of the segment in accordance with subpart K is allowed.

Proposed Method 6: In-Line Inspection in-lieu of Hydrostatic Pressure Testing (Proposed §192.624(c)(6))

AGA recommends the addition of a method that is specifically targeted to performing in-line inspection in-lieu of hydrostatic testing. As discussed previously in the section of these comments on Engineering Critical Assessment, AGA believes that there needs to be a pure in-line inspection solution within the methods for MAOP Verification. PHMSA alludes to this in the PRIA, by stating “PHMSA assumed an operator would run three ILI tools per assessment consistent with its proposal for ILI assessments performed to re-establish MAOP in accordance with 192.624.”

AGA continues to believe that there needs to be a technology based solution that realizes the same or greater level of safety as a Subpart J pressure test as provided in Method 1. In fact, in many respects, ILI can provide greater opportunity to enhance safety than pressure testing. Unlike a pressure test, which is pass/fail, ILI reveals information about the condition of the pipe, including the identification of sub-critical anomalies that remain in the pipeline after a successful pressure test. In-line inspection tools are ever improving and the ability to use ILI in lieu of a pressure test is much more impactful and meaningful for the industry than the cumbersome and burdensome ECA approach. AGA remains confident that the industry can ultimately reach engineering consensus on the necessary capabilities of an ILI tool to be used in lieu of a pressure test.

Since PHMSA’s publishing of the IVP chart in June 2013, ILI vendors have been working feverishly to provide a series of tools that can find defects that would fail a 1.25 times MAOP pressure test. While AGA understands that PHMSA may be hesitant to codify a solution that incorporates unproven technology, the pace by which this technology is improving indicates that it is nearing completion. Therefore, it is reasonable for PHMSA to include a technical solution that realizes the same or greater level of safety than a pressure test.

As proposed, operators will be required to utilize the Alternative Technology method once the technology is available, which will inundate PHMSA with notifications of its use. PHMSA could incorporate a methodology with the proper criteria that will allow for the use of in-line inspection in-lieu of hydrostatic pressure testing,

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without the need for notifications. AGA suggests the following language be incorporated as a method in §192.624(c).

(6) Method 6: In-Line Inspection in-lieu of Hydrostatic Pressure Testing – Conduct in-line inspection assessments utilizing one or more in-line inspection tools that have been qualified to detect defects that would fail pressure test equal to the verified MAOP divided by the greater of either 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

Proposed Method 7: Alternative Technology (Proposed §192.624(c)(7))

AGA does not believe it is PHMSA’s role to serve as the gatekeeper to determine what technology is acceptable or not for operators to use. In the past, PHMSA has not responded in a timely manner to operator requests to use new technology that would have enhanced pipeline safety. It is critical to note that under Subpart O, operators are left waiting for PHMSA to render approval of whether their plans to use alternate technology for integrity assessment are acceptable. This wait can and does go beyond 180 days, in which PHMSA may negate all the work that has been conducted by the operator.

PHMSA’s proposed requirements for operators to use “Alternative Technology” are simply impracticable. It would require that the operator provide to PHMSA a host of information related to the use of the alternative technology at least 180 days prior to its use. Yet there is no provision that would require PHMSA to respond in a timely manner, suggesting that PHMSA can respond the day before the start of the project or worse yet, months or even years after the project’s planned initiation or even completion. This uncertainty cannot be reconciled with the planning and business considerations that an operator must utilize when evaluating how to invest in technology and which methods to use for MAOP Verification. AGA believes operators should be granted the ability to initiate the use of alternative technology for the purpose of MAOP Verification. It would be incumbent upon the operator to be able to justify the technical merits of this alternative technology in how it validates MAOP.

(7) Method 7: Alternative Technology - Operators may use an alternative technical evaluation process that provides a sound engineering basis for establishing or verifying maximum allowable operating pressure. If an operator elects to use alternative technology, the operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph § 192.624(e) of this section. The operator must submit the alternative technical evaluation to PHMSA with the notification and obtain a “no objection letter” from the Associate Administrator of Pipeline Safety prior to usage of alternative technology. The operator must be prepared to provide technical justification that demonstrates the prudence of the approach used. The justification must include the following details:

(i) Descriptions of the technology or technologies to be used for tests, examinations, and assessments, establishment of material properties, and analytical techniques, with like similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated.

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

(iii) Methodology and criteria used to determine reassessment period or need for a reassessment including references to applicable regulations from this Part and industry standards;
Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;

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

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

Remediation methods with proven technical practice;

Schedules for assessments and remediation;

Operational monitoring procedures;

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

Documentation requirements for the operator’s process, including records to be generated.

Ensure clarity in the record retention requirement (192.624(f))

Requirements to retain records, as well as the quality of records, must only be applied prospectively. AGA understands the proposed records section associated with MAOP Verification to apply only to actions an operator would take to specifically comply with the proposed MAOP Verification requirements in §192.624 after the effective date of the rule. Consistent with AGA’s comments previously, AGA suggests that PHMSA delete the term “reliable.” As AGA has outlined in its comments under proposed section §192.619(f), PHMSA should add clarification under that section to ensure that pipeline segments that have their MAOP established per §192.624 do in fact have a valid MAOP for the purpose of fulfilling §192.619 requirements.

Reasonable Completion Deadlines Given Complexity and Associated Proposed Requirements

AGA estimates based on member-submitted data that under the proposed MAOP Verification requirements, AGA member operators will need to verify approximately 13,600 miles of transmission pipe. This represents roughly 23% of the respondent’s total transmission pipeline mileage. AGA believes that PHMSA’s proposal that operators develop a completion plan within one year of a final rule is reasonable, so long as the expectation for the plan is that it is a high-level document that is subject to further refinement and improvement. Such flexibility is necessary given the number of miles, the need to evaluate and identify the appropriate MAOP Verification method for each pipeline segment, and the reality that as operators become more familiar with the intricacies of using the different Methods for MAOP Verification, the Methods may be selected differently.

AGA recognizes that this is higher than PHMSA’s mileage estimates in the PRIA. AGA addresses PHMSA’s PRIA estimates in Section V, but believes that the differences in the estimates is the result of PHMSA’s reliance on the annual report data, despite the fact that operators do not enter this information in a consistent manner. Operators have taken a range of approaches, including not entering mileage associated with incomplete records in categories if they have complete records for one category, as well as the opposite, entering mileage associated with incomplete records even though they have complete records for one category. Based on these inconsistencies, the data included in the annual report does not provide an accurate representation of the mileage that would be subject to the proposed MAOP Verification requirements.
Although AGA supports the development of a MAOP Verification plan within one-year, AGA believes that PHMSA’s proposal that 50% of the mileage be completed within 8 years and 100% of the mileage within 15 years is infeasible. Given the significant concerns with PHMSA’s proposed MAOP Verification methods, PHMSA needs to understand that many operators will be forced to select pipe replacement as a primary method for MAOP Verification. The proposed timeframes of eight and fifteen years are not feasible when considering the coordination of resources necessary to replace pipe, particularly for operators who have the highest mileage of pipe impacted by this rule. Pipeline operators with a significant mileage of “grandfathered” pipelines due to the vintage of their system, will enter a huge undertaking of addressing those pipelines through both MAOP Verification and Material Verification. Two of AGA’s members that have greater than 1,500 miles of transmission pipeline have reported that nearly 95% of their pipeline miles will be required to undergo the requirements of §192.624. Even those AGA members with over 5,000 miles of transmission pipelines, as prescribed in the Proposed Rule, would be required to perform MAOP Verification on over 1,000 of those miles. For 1,000 miles to be replaced in 15 years, operators would be required to replace nearly 67 miles per year. AGA does not believe PHMSA has adequately appreciated the enormous quantity of work that will be required to meet the Proposed Rule and therefore should reconsider the timeframe for completion of the MAOP Verification Process. The resources available to the industry to perform pipe replacement for MAOP Verification will be limited due to ongoing integrity management programs for transmission and distribution operators and the current replacement of cast iron, bare steel and other distribution assets that may no longer be fit for service.

AGA also is concerned that PHMSA’s deadlines are based on “pipeline mileage,” whereas a pipeline is subject to MAOP Verification by “pipeline segment.” AGA suggests that the milestones should be based on “pipeline segments.” Not only is this consistent with the applicability of MAOP Verification, but this removes the incentive to address low-risk lengthier pipelines ahead of shorter pipe with comparatively higher risks. AGA strongly recommends that PHMSA allow 20 years under §192.624(b) for the industry to complete this work with 50% of the pipe segments completed within 10 years (rather than the mileage). AGA suggests the following changes to the proposed regulatory language for the Completion Date.

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

1. The operator must develop and document a plan for completion of all actions required by this section by [insert date that is 1 year after the effective date of rule].

2. The operator must complete all actions required by this section on at least 50% of the mileage of locations pipeline segments that meet the conditions of § 192.624(a) by [insert date that is 8 10 years after the effective date of rule].

3. The operator must complete all actions required by this section on 100% of the mileage of locations pipeline segments that meet the conditions of § 192.624(a) by [insert date that is 15 20 years after the effective date of rule].

4. If operational and environmental constraints limit the operator from meeting the deadlines in § 192.614 (b)(2) and (3) above, the operator may petition for an extension of the completion deadlines by up to one year, upon submittal of a notification to the Associate Administrator of the Office of Pipeline Safety in accordance with paragraph (e). The notification must include an up-to-date plan for completing all actions in accordance with (b)(1), the reason for the requested extension, current status, proposed completion date,
remediation activities outstanding, and any needed temporary safety measures to mitigate the impact on safety.

*The Regulatory Impact Assessment needs to adequately account for impacted pipelines and the actual cost to perform MAOP Verification Methods*

AGA has significant concerns with PHMSA’s estimated cost and justification for the MAOP Verification requirements that are addressed in detail in Section V, but summarizes those concerns here.

**Scope of PRIA**

PHMSA’s organization of its impact assessment for MAOP Verification makes it extremely difficult, if not impossible, for stakeholders to review and make meaningful comment on the PRIA. PHMSA has broken down the impacts of the proposed MAOP Verification requirements in a manner that is inconsistent with and narrower in scope than how the proposed regulatory text is structured. For example, although the proposed MAOP Verification requirements make no distinction between pipelines operated above and below 30% SMYS, PHMSA has chosen partially to break out its regulatory impact assessment in this manner. See PRIA, pages 33, 57. The following table displays how PHMSA has categorized pipelines subject to the proposed MAOP Verification requirements in (1) the Proposed Rule, (2) the PRIA.

<table>
<thead>
<tr>
<th>COMPARISON OF SCOPE OF PROPOSED MAOP VERIFICATION (192.624(A)) WITH PRIA ESTIMATES</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pipelines With Manufacturing- and Construction-Related Defects Resulting in Reportable Incidents</strong></td>
</tr>
<tr>
<td>Proposed Regulatory Text (§192.624(a)(1))</td>
</tr>
<tr>
<td>• High consequence areas</td>
</tr>
<tr>
<td>• Class 3 and class 4 locations</td>
</tr>
<tr>
<td>• Moderate Consequence Area that is able to accommodate inspection by means of an instrumented in-line inspection tool.</td>
</tr>
<tr>
<td><strong>Pipelines With Inadequate Pressure Test Records</strong></td>
</tr>
<tr>
<td>Proposed Regulatory Text (§192.624(a)(2))</td>
</tr>
<tr>
<td>• High consequence areas</td>
</tr>
<tr>
<td>• Class 3 and class 4 locations</td>
</tr>
<tr>
<td><strong>Previously Untested Pipelines/Pipelines Establishing MAOP Under §192.619(c)</strong></td>
</tr>
<tr>
<td>Proposed Regulatory Text (§192.624(a)(3))</td>
</tr>
<tr>
<td>• High consequence areas</td>
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<td>• Moderate Consequence Area that is able to accommodate inspection by means of an instrumented in-line inspection tool.</td>
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Breaking out the assessment in this manner requires PHMSA to make additional estimates of the mileage of pipelines operating at different pressure levels. *See, e.g., PRIA Table 3-2 at 34. It also makes it incredibly difficult*
to evaluate the potential impact. Of more concern, it also has resulted in PHMSA not including in the PRIA categories of pipelines that would be subject to the proposed MAOP Verification. Specifically, PHMSA has failed to account for the impact on pipelines in HCAs that operate at 20% SMYS or less and the impact on pipelines with manufacturing- and construction-related defects that result in a reportable in-service incident (proposed §192.624(a)(1)).

Assumptions and Methodology

Also, AGA fundamentally disagrees with many of PHMSA’s assumptions underlying its estimate of the impact of the proposed MAOP Verification requirements.

AGA disagrees with PHMSA’s expectation that most operators will use ILI in conjunction with engineering critical assessment or pressure testing to verify MAOP. See PRIA, pages 33, 49, 60. As discussed in detail above, due to the prescriptive and onerous requirements associated with engineering critical assessment, this method for MAOP Verification is not a viable option for most operators. In fact, due to the significant concerns regarding all of the proposed MAOP Verification methods, AGA members report that pipe replacement would be the preferred MAOP Verification method, along with pressure testing. Pipeline replacement should be the last resort and required when the safety, financial, and operational considerations eliminate the feasibility of the other methods. The fact that this is a preferred approach demonstrates the unreasonableness of PHMSA’s proposed MAOP Verification methods and that the Congressional mandates to consider timing, cost and service disruptions have not been met.

PHMSA bases its position that most operators will perform ILI in conjunction with engineering critical assessment or will pressure test to verify MAOP on various data from annual reports as well as PHMSA’s “best professional judgment.” In general, PHMSA believes that operators will ILI all ILI-capable lines, will pressure test the same percentage of lines previously annually tested, and will update the remaining lines to be ILI capable. By making these broad assumptions, PHMSA fails to consider the unique challenges associated with MAOP Verification on the pipelines subject to §192.624 and the prescriptive and onerous nature of the proposed MAOP Verification methods that make them more challenging to perform than traditional assessment methods.

PHMSA fails to account for any cost or distinction between performing an ILI on a pipeline and performing the ILI/ECA MAOP assessment method on a pipeline. Nowhere in the PRIA does PHMSA estimate or take into account the cost of the ECA. As a result, PHMSA’s assumption that if a pipeline is ILI capable, then an operator will choose the ILI/ECA option is flawed.

PHMSA’s assumptions regarding the percentage of pipelines that will use pressure testing is based in part on operator’s prior use of pressure testing and PHMSA’s best professional judgment. PHMSA’s assumptions ignore the distinctions between pressure testing as an integrity management assessment method and the MAOP Verification requirements, which, for “legacy” pipe and construction- and manufacturing-related incidents, would require a hydrostatic spike pressure test. Performing a hydrostatic spike pressure test on existing pipelines presents additional challenges not present when gas is used to conduct a pressure test. Furthermore, the differences between the regulatory options and requirements that an operator must consider when choosing an assessment method for integrity management purposes versus what PHMSA is proposing for MAOP Verification, for example the use of direct assessment, mean that a past preference for pressure test for integrity assessment does not mean that an operator will select a pressure test for MAOP Verification.
Finally, PHMSA assumes that the difference in pipeline mileage between predicted percentage of pressure testing and the mileage of ILI capable will be modified to accommodate ILI technology. PHMSA fails to recognize the unique challenges associated with pipelines subject to the proposed MAOP Verification requirements that make them less likely to be ILI-capable. For example, these pipelines are generally older (evidenced by their reliance on the “grandfather” clause) and were not designed to accommodate such a tool. Upgrading these pipelines to accommodate an ILI tool is especially challenging and problematic. In fact, for HCAs, given that these lines have already been subject to TIMP requirements that could be complied with through ILI, if the pipelines have not already been upgraded to ILI capable there is a strong likelihood that they cannot be upgraded to be ILI capable in a manner that is feasible and practical.

Estimate of Costs and Benefits

PHMSA’s estimated unit costs for assessment are applicable also to the proposed requirements for assessments outside of HCAs. Similarly, PHMSA’s estimated benefits relate not just to MAOP Verification, but also Material Verification, and pipeline assessments and repairs outside of HCAs. AGA has significant concerns regarding PHMSA’s estimation of unit costs for assessments and the estimated associated benefits. However, because PHMSA has grouped its calculations together in such a way, AGA discusses its concerns regarding these approaches and PHMSA’s estimates in Section V of these comments on the PRIA.

Proposed Regulatory Language

Below is a summary of AGA’s proposed regulatory language for §192.624. The language, and AGA’s other proposed regulatory language changes, can be found in Appendix A.

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

(a) Applicable Locations

(1) The pipeline segment has experienced a reportable in-service incident as defined in §191.3 since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations:
   (i) A high consequence area as defined in §192.903;
   (ii) A class 3 or class 4 location; or
   (iii) A moderate consequence area as defined in §192.9 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (i.e., “smart pigs”).

(1) For pipelines not relying on 192.619(c) to determine MAOP, pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment are incomplete or unavailable, including, but not limited to, records required by § 192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline is located in one of the following locations:
   (i) A high consequence area as defined in §192.903; or
   (ii) A class 3 or class 4 location

(2) The pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) of this subpart before [insert effective date of rule], operates at greater than 30% SMYS and is located in one of the following locations:
(i) A high consequence area as defined in §192.903.
(ii) A class 3 or class 4 location; or
(iii) A moderate consequence area as defined in §192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (i.e., “smart pigs”).

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

(1) The operator must develop and document a plan for completion of all actions required by this section by [insert date that is 1 year after the effective date of rule].

(2) The operator must complete all actions required by this section on at least 50% of the mileage of locations pipeline segments that meet the conditions of §192.624(a) by [insert date that is 8 10 years after the effective date of rule].

(3) The operator must complete all actions required by this section on 100% of the mileage of locations pipeline segments that meet the conditions of §192.624(a) by [insert date that is 15 20 years after the effective date of rule].

(4) If operational and environmental constraints limit the operator from meeting the deadlines in §192.614 (b)(2) and (3) above, the operator may petition for an extension of the completion deadlines by up to one year, upon submittal of a notification to the Associate Administrator of the Office of Pipeline Safety in accordance with paragraph (e). The notification must include an up-to-date plan for completing all actions in accordance with (b)(1), the reason for the requested extension, current status, proposed completion date, remediation activities outstanding, and any needed temporary safety measures to mitigate the impact on safety.

(c) **Maximum Allowable Operating Pressure Determination-Verification.** The operator of a pipeline segment meeting the criteria in paragraph (a) above must establish verify its maximum allowable operating pressure using one of the following methods:

(1) **Method 1: Pressure test.**

(i) Perform a pressure test in accordance with §192.505(c)-Subpart J of this Part. The maximum allowable operating pressure will be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or §192.620(a)(2)(ii).

(ii) If the pipeline segment includes legacy pipe or was constructed using legacy construction techniques or the pipeline pipe with a longitudinal joint factor less than 1.0, as defined in §192.113, was manufactured by a process no longer accepted by industry standards, was constructed using construction techniques or practices no longer acceptable for new construction under part 192, has experienced an incident, as defined by §191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, including but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking, that was not otherwise addressed by the operator, then the operator must perform a spike pressure test in accordance with §192.506. The maximum allowable operating pressure will be equal to the test pressure specified in §192.506(c) divided by the greater of 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or §192.620(a)(2)(ii).

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

(2) Method 2: Pressure Reduction - The pipeline maximum allowable operating pressure will be no greater than the pressure described in §192.620(c)(2)(i). The highest actual operating pressure sustained by the pipeline during the 18 months preceding [insert effective date of rule]...The value used as the highest actual sustained operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest pressure value for the entire segment or using the operating pressure gradient (i.e., the location-specific operating pressure at each location).

(i) Baseline pressure determination:

(A) [Note: Only applicable if PHMSA keeps the proposed §192.624(a)(1)]: For pipelines that meet the applicability of §192.624(a)(1) the pipeline maximum allowable operating pressure will be no greater than the actual operating pressure at the time of the reportable in-service incident divided by the greater of 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

(B) For pipelines that meet the applicability of §192.624(a)(2) and §192.624(a)(3) the pipeline maximum allowable operating pressure will be no greater than the highest documented operating pressure sustained by the pipeline divided by 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or §192.620(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period.

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

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

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

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

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

(v) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor, the operator must notify PHMSA in accordance with paragraph (e) of this section no later than seven calendar days after establishing the reduced maximum allowable operating pressure. The notification must include the following details:
(A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in §192.624(c)(2);

(B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with paragraph (d) of this section;

(C) Justification that establishing maximum allowable operating pressure by another method allowed by this section is impractical;

(D) Justification that the reduced maximum allowable operating pressure determined by the operator is safe based on analysis of the condition of the pipeline segment, including material records, material properties verified in accordance §192.607, and the history of the segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned.

(E) Planned duration for operating at the requested maximum allowable operating pressure, long term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts in metallurgy and fracture mechanics.

(vi) Any reductions in MAOP voluntarily initiated by the operator from December 31, 2003 until the date that the operator elects to verify MAOP using Method 2 shall be considered as a Pressure Reduction conducted under §192.624(c)(2).

(3) Method 3: Engineering Critical Assessment

[See INGAA’s Comments]

(4) Method 4: Pipeline Replacement – Replace the pipeline segment.

(5) Method 5: Pressure Reduction for Segments with Small Potential Impact Radius and Diameter – Pipelines with a maximum allowable operating pressure less than 30 percent of specified minimum yield strength, a potential impact radius (PIR) less than or equal to 150-200 feet, nominal diameter equal to or less than 8-inches, and which cannot be assessed using inline inspection or pressure test, may establish the maximum allowable operating pressure as follows: performing the actions in either (i) or (ii) as listed below:

(i) Reduce the pipeline maximum allowable operating pressure to no greater than the pressure described in §192.624(c)(5)(i)(A), (B), or (C). during 18 months preceding [insert effective date of rule]. The reduced maximum allowable operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire segment or the operating pressure gradient (i.e., the location specific operating pressure at each location).

(A) For pipelines that meet the applicability of §192.624(a)(1) the pipeline maximum allowable operating pressure will be no greater than the actual operating pressure at the time of the reportable in-service incident divided by 1.1.

(B) For pipelines that meet the applicability of §192.624(a)(2) and §192.624(a)(3) the pipeline maximum allowable operating pressure will be no greater than the highest documented operating pressure sustained by the pipeline divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of eight hours during one continuous 30-day period.
(C) Any reductions in MAOP voluntarily initiated by the operator from December 31, 2003 until the date that the operator elects to verify MAOP using Method 2 shall be considered as a Pressure Reduction initiated under 192.624(c)(5); or

(ii) Perform the following additional actions to ensure the safety of the pipeline.

(A) Conduct external corrosion direct assessment in accordance with § 192.925, and internal corrosion direct assessment in accordance with § 192.927;

(B) Develop and implement procedures for conducting non-destructive tests, examinations, and assessments for cracks and crack-like defects, including but not limited to stress corrosion cracking, selective seam weld corrosion, girth weld cracks, and seam defects, for pipe at all excavations associated with anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, or any other reason for which the pipe segment is exposed, except for segments exposed during excavation activities that are in compliance with § 192.614;

(C) Conduct monthly patrols in Class 1 and 2 locations, at an interval not to exceed 45 days; weekly patrols in Class 3 locations not to exceed 10 days; and semi-weekly patrols in Class 4 locations, at an interval not to exceed six days, in accordance with § 192.705;

(D) Conduct monthly, instrumented leakage surveys in Class 1 and 2 locations, at intervals not to exceed 45 days; weekly leakage surveys in Class 3 locations at intervals not to exceed 10 days; and semi-weekly leakage surveys in Class 4 locations, at intervals not to exceed six days, in accordance with § 192.706; and

(E) Odorize gas transported in the segment, in accordance with § 192.625;

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

(iii) Under Method 5, future uprating of the segment in accordance with subpart K is allowed.

(6) Method 6: In-Line Inspection in-lieu of Hydrostatic Pressure Testing – Conduct in-line inspection assessments utilizing one or more in-line inspection tools that have been qualified to detect defects that would fail pressure test equal to the verified MAOP divided by the greater of either 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

(7) Method 7: Alternative Technology - Operators may use an alternative technical evaluation process approach that provides a sound engineering basis for establishing verifying maximum allowable operating pressure. If an operator elects to use alternative technology, the operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph § 192.624(e) of this section. The operator must submit the alternative technical evaluation to PHMSA with the notification and obtain a “no objection letter” from the Associate Administrator of Pipeline Safety prior to usage of alternative technology. The operator must be prepared to provide technical justification that demonstrates the prudence of the approach used. The justification notification must include the following details:

(i) Descriptions of the technology or technologies to be used for tests, examinations, and assessments, establishment of material properties, and analytical techniques, with like-similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated.
(ii) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered; and

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

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

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

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

(vii) Remediation methods with proven technical practice;

(viii) Schedules for assessments and remediation;

(ix) Operational monitoring procedures;

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

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

(d) Fracture Mechanics modeling for failure stress and crack growth analysis.—[See AGA’s Comments on Fracture Mechanics].

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

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

(2) Sending the notification to the Information Resources Manager by facsimile to (202) 366-7128; or

(3) Sending the notification to the Information Resources Manager by e-mail to InformationResourcesManager@dot.gov.

(4) An operator must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

(f) Records. For gas transmission pipelines that meet the applicability of §192.624, after [insert effective date of rule] Each operator must keep for the life of the pipeline reliable, traceable, verifiable, and complete records of the investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions made in accordance with the requirements of this section.

a. Fracture Mechanics

Within PHMSA’s proposed MAOP Verification requirements (§192.614(d)), PHMSA has introduced a prescriptive requirement to perform fracture mechanics modeling for failure stress pressure and crack growth analysis. This new requirement applies to all pipelines where “an operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to an assessment, leak, failure, or
manufacturing vintage histories, or any other available information about the pipeline.” AGA emphasizes the following four positions on fracture mechanics modeling:

1. Fracture mechanics is an analysis that has a limited place in preventing pipeline failures in some (relatively unusual) applications. The regulation should not prescribe fracture mechanics calculations be performed for such a broad range of applications.
2. The set of pipelines for which fracture mechanics requirements apply should be limited to those that are at greatest risk of cracking threats, specifically legacy pipe operating over 30% SMYS.
3. Fracture Mechanics is a highly complex and specialized field that may not always predict failure pressures accurately. PHMSA should acknowledge the complexity and impact of this new requirement within the PRIA.
4. PHMSA’s proposed code language is overly prescriptive. Experts in fracture mechanics should be given the latitude to conduct analyses in ways appropriate for the situation.

(1) \textit{Fracture mechanics is an analysis that has a limited place in preventing pipeline failures in some (relatively unusual) applications.}

Fracture mechanics is an analysis that has a limited place in preventing pipeline failures, including the following two cases. Industry subject matter experts and AGA have asserted that it is not necessary to perform such analyses on all or even a large percentage of transmission pipelines:

(A) Determination of remaining life for the largest defect that could survive a pressure test. This is relevant only when an operator wishes to verify the MAOP of the pipeline using Engineering Critical Assessment and/or a previous pressure test with a test pressure/MAOP ratio less than prescribed in the regulation.
(B) Calculating the failure pressure of indicated or proven defects that cannot be repaired immediately.

Gas transmission pipeline segments with records of a pressure test to at least 1.25 times MAOP do not have a history of failure by cyclic fatigue. An analysis by Battelle Corporation of over 500 failed pipelines demonstrated that only liquid pipelines, not natural gas pipelines, exhibited failures from cyclic fatigue crack growth. The reason for this observation is that natural gas transmission pipelines generally have low levels of pressure cycling, which leads to extremely low fatigue crack growth rates. As a result, requiring calculations of cyclic fatigue remaining life does not contribute to safety, except in very specific cases.

For purposes of verifying the MAOP on pipelines without a record of a pressure test, fracture mechanics could have a role if an operator wishes to use a lower test pressure to MAOP ratio than those prescribed in §192.619(a)(2). As discussed above, natural gas pipelines that have been pressure tested to at least 1.25 times MAOP do not have a history of failure by cyclic fatigue. These segments do not require further analysis to ensure the stability of manufacturing and construction defects. Some transmission pipeline segments have historically been tested to lower levels, as currently allowed by §192.619, or pressure test records are not available. In this case, fracture mechanics analyses, in part, could be used to justify continued safe operation of the pipeline without a pressure test.
Another situation in which fracture mechanics analysis could be useful is when ILI anomalies identified as crack-like cannot be directly examined in a reasonable time frame due to issues such as accessibility or permit restrictions. Example situations could include an anomaly identified under a freeway crossing or in a wetland location. In this case, fracture mechanics could be useful to justify a scheduled or monitored response to such an indication, and determine whether a temporary pressure reduction is warranted.

(2) The set of pipelines for which fracture mechanics requirements apply should be limited to those that are at greatest risk of cracking threats, specifically pipe with a longitudinal joint factor less than 1.0 and operating over 30% SMYS.

Given the rarity of cyclic fatigue damage in natural gas pipelines, it is not reasonable to require fracture mechanics analysis on any pipeline that has any potential to contain a crack. Regulatory requirements should be focused on categories of pipelines that are at significant risk. However, it appears that PHMSA’s proposed language in §192.624(d) applies to all pipelines within the scope of §192.624. Similarly, it appears that the fracture mechanics reference in §192.917(e)(2) applies to all HCA covered segments, regardless of operating stress level or manufacturing method. PHMSA’s proposed language in §192.624(c)(1) (Method 1: Pressure test) will require fracture mechanics analysis on any pipeline being pressure tested to verify MAOP. These are overly broad categories of pipelines, many of which are at insignificant risk of cracking threats.

PHMSA’s proposed language in §192.624(d) which defines where fracture mechanics analysis must be performed is far too broad: “the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline”. As written, it could apply to virtually any pipeline. Such a broad scope makes any requirement to perform an analysis overly broad and unnecessarily burdensome. AGA suggests that the criteria should be revised to “the pipeline segment contains pipe with a longitudinal joint factor less than 1.0 as defined in §192.113, or was known to be installed using construction techniques no longer recognized as acceptable for new construction under Part 192 that could make it susceptible to cracks or crack-like defects”. This would focus the requirements on those segments at risk of crack defects, and clarify that analysis is not required for those lines not at risk. This language is consistent with AGA’s comments on the definitions of Legacy pipe and Legacy Construction Techniques in Section IV.H of these comments.

AGA also believes the scope should be further narrowed to only those transmission pipelines operating at a hoop stress greater than 30% SMYS, as pipelines that operate below 30% SMYS have a strong tendency to leak rather than rupture. On page 20813 of the FR notice of the Proposed Rule, PHMSA references a recent study that provides support for limiting the threshold to pipelines that operate at greater than 30% SMYS as follows: “The Kiefner/GTI report evaluated theoretical fracture models and supporting test data in order to define a possible leak-rupture threshold stress level. The report pointed out that ‘no evidence was found that a propagating ductile rupture could arise from an incident attributable to any one of these causes in a pipeline that is operated at a hoop stress level of 30% of SMYS or less.”
(3) PHMSA should acknowledge the complexity and impact of this new requirement within the PRIA.

AGA reminds PHMSA that the prescriptive nature of these requirements makes it important that the associated costs be included in PHMSA’s PRIA. Even with AGA’s simplified approach, this is a very complex process that will likely require outside consulting for virtually all of AGA’s operating companies. In fact, of the 39 member companies that participated in a survey to understand the scope of this rule 30 stated that they do not have an individual on staff that is a “subject matter expert in metallurgy and fracture mechanics”, and therefore, would have to outsource any work related to fracture mechanics.

Historically, operators have not had a need to collect toughness data. As a result, toughness data is not readily available for the majority of pipelines. The use of conservative defaults, especially the overly conservative default values in PHMSA’s Proposed Rule, may result in an unacceptably short remaining life. Collecting this data for pipe already in the ground would be extremely expensive, with minimal benefit to pipeline safety. Such an expense should be accounted for in the PRIA.

As operators begin to use in-line inspection for detection and sizing of cracks and crack-like defects, the limitations of those technologies will need to be accounted for in predicted failure pressure calculations. For ILI solutions available today, the confidence levels for the sizing of the cracks is 90% and 80% for the probability of detection. These confidence levels could result in an operator’s inability to thoroughly detect cracks and crack-like defects, or may result in the misidentification of cracks as metal loss or other defect conditions. Even direct examination of cracks is still limited in the accurate sizing and characterization of certain defect types and geometries. Such a large increase in the number of required direct examinations should be accounted for in the PRIA.

(4) PHMSA’s proposed code language is overly prescriptive. Experts in fracture mechanics should be given the latitude to conduct analyses in ways appropriate for the situation.

Given the myriad of possible situations in which fracture mechanics may be applied, it is not appropriate for PHMSA to prescribe such parameters as the toughness to be used, the fatigue crack growth equation to be used, the sensitivity analysis to be performed, or fracture toughness regime (linear elastic versus ductile). Experts in the science of fracture mechanics can make the best judgments as to how such analyses should be conducted.

Additionally, PHMSA’s proposed default Charpy V-notch toughness values (5.0 ft-lb for body cracks and 1.0 ft-lb for ERW seam bond line defects) are extremely over-conservative and will therefore result in predicted failure pressures that are significantly less than the actual failure pressures in most cases. Industry studies are currently underway to justify more appropriate conservative default values. Conservative default values of 15.0 ft-lb for body cracks and 5.0 ft-lb for seam bond line cracks are considered to be suitable based on preliminary data.

The following is AGA’s proposed changes to §192.624(d). These proposed changes can also be found in Appendix A later in the document.
§192.624(d) Fracture mechanics modeling

(a) **Applicability**: Pipelines that contain or may be susceptible to cracks or crack-like defects on pipe with a longitudinal joint factor less than 1.0 as defined in §192.113, or was known to be installed using construction techniques no longer recognized as acceptable for new construction under part 192, and that operate at a hoop stress greater than 30% SMYS must be analyzed under the following circumstances:

(1) Operators conducting MAOP Verification as described in 192.624, using Method 3 (Engineering Critical Assessment) or Method 6 (Alternative Technology) must calculate remaining life of the segment considering the cyclic fatigue mechanism. Additionally, operators using Method 1 (Pressure Test) or Method 2 (Pressure Reduction), and who wish to use a less conservative pressure test or pressure reduction factor, must calculate remaining life of the segment considering the cyclic fatigue mechanism.

(2) Operators responding to crack or crack-like indications from ILI inspections must calculate failure pressure of the anomaly, and must calculate remaining life if the anomaly cannot be directly examined within one year from the date of discovery.

(b) Fatigue analysis must be performed using a recognized form of the Paris Law or other technically appropriate engineering methodology validated by a subject matter expert in metallurgy and fracture mechanics to give conservative predictions of flaw growth and remaining life.

(1) If actual material toughness is not known or not adequately documented for fracture mechanics modeling for failure stress pressure, the operator must use a conservative Charpy energy value to determine the toughness based upon the material documentation program specified in § 192.607; or use maximum Charpy energy values of 15.0 ft-lb for body cracks; 5.0 ft-lb for cold weld, lack of fusion, and selective seam weld corrosion defects; or other appropriate values based on technology or technical publications that an operator demonstrates can provide a conservative Charpy energy values of the crack-related conditions of the line pipe.

(2) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other). Examples of suitable models include: for the brittle failure mode, the Raju/Newman Model (Task 4.5); for the ductile failure mode, the Modified LnSec model (Task 4.5).

(3) The operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired, but within 15 years. The operator must determine and document if further pressure tests or use of other methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.

(c) The analysis required by this paragraph must be reviewed and confirmed by a subject matter expert in both metallurgy and fracture mechanics.

**B. Moderate Consequence Areas**

PHMSA is proposing to create a new classification for transmission pipelines, Moderate Consequence Areas (MCAs). In PHMSA’s proposal, MCAs will be included in the applicable pipelines for the proposed requirements for Pipeline Assessments Outside HCAs (§192.710) and for MAOP Verification (§192.624).
AGA supports the expansion of integrity management principles beyond HCAs as outlined in AGA’s Commitment to Enhancing Safety\(^{47}\). However, AGA believes the introduction of a new pipeline classification as currently proposed will result in a burdensome MCA identification process and significant additional recordkeeping requirements that will divert resources away from the true intent of improving pipeline safety. If codified as currently proposed, operators foresee spending a significant amount of resources on the administration of MCAs: tracking where people congregate and gather, quantifying the number of people at each location, and the frequency of those gatherings. AGA firmly believes this resource allocation is better spent on tangible actions that will result in true safety improvements. AGA therefore encourages PHMSA to consider alternative language to the proposed Moderate Consequence Area and Occupied Site definitions that will provide operators with an approach to identifying MCAs and allow operators to invest resources more effectively while enhancing public safety.

AGA’s proposal mirrors the two-methodology approach used in the definition of High Consequence Areas (HCAs) in the existing §192.903, which allows for identification based on class location or by the pipeline’s potential impact radius. AGA’s proposed MCA method would allow operators to include as MCAs all Class 2 locations as well as all Class 1 locations located within a specific proximity to specific roadways. This approach would apply the proposed regulatory requirements to an equivalent amount of pipeline miles, while alleviating the burden of MCA identification for many operators. AGA’s proposal would also still allow operators the ability to go through the MCA identification based on the pipeline’s potential impact circle. AGA believes that this approach is consistent with PHMSA’s description that the MCA concept imposes minimal burden on operators and is similar to the HCA process.\(^{48}\)

Through this proposal, AGA continues to support the intent of the NTSB Recommendation P-14-01:

“Revise gas regulations to add principal arterial roadways including interstates, other freeways and expressways, and other principal arterial roadways as defined by FHA to the list of “identified sites” that establish HCAs.”\(^{49}\)

In AGA’s proposed definition for MCAs, all pipelines near major roadways are captured in both methodologies, regardless of their Class Location. However, AGA echoes INGAA’s comments on the modification to PHMSA’s proposed MCA definition to remove the reference to “a right-of-way” for the designated roadways. As PHMSA acknowledges, the Federal Highway Administration’s Highway Functional Classification Concepts is spatially inaccurate and cannot be relied upon to definitely designate the right-of-way. See 81 Fed. Reg. 40757, 40758 (June 22, 2016). The width of rights-of-way for roadways are variable and cannot be seen with the naked eye. Detailed records of rights-of-way often are not maintained in digital format, and if they are, the accuracy cannot be guaranteed and may need to be verified by the operator. Identifying and mapping the location of each right-of-way based on documentation located in municipal offices maintaining these deeds would be an enormously costly endeavor that would have to be continuously updated as properties exchange hands and right of ways can change over time. The significant cost associated through identifying the right-of-way has not been acknowledged by PHMSA. Moreover, the rights-of-way themselves do not adequately represent the consequence

\(^{47}\) AGA Commitment to Enhancing Safety

\(^{48}\) PHMSA describes its proposed criteria for determining MCA location as using the same process and the same definitions as currently used to identify HCAs. 81 Fed. Reg. 20732.

\(^{49}\) NTSB Report: Sissonville, WV
area that the NTSB was attempting to capture since they can vary significantly from near the edge of pavement to several hundred feet away. Instead AGA suggests that the right-of-way reference be removed and replaced with “edge of existing pavement”. AGA also notes that PHMSA has not provided justification for this requirement separate from the NTSB recommendation.

AGA also supports API’s comments that the NTSB’s recommendation intention is met through the revision of applying the 4-lane qualification to the entire series of roadway types, not just the principal arterial roadways. See AGA’s proposed definition for MCA in Appendix A, §192.3.

AGA shares the same concerns as all other industry stakeholder groups that a publicly available and accepted data source must be provided for the identification of the selected roadways. If PHMSA is to require that MCAs be identified in part by these roadways, PHMSA must provide operators with a source for this information. Without this data source, there would be significant regulatory uncertainty as to which roadways truly meet the Federal Highway Administration’s definitions. In fact, as PHMSA has acknowledged, the Federal Highway Administration’s Highway Functional Classification Concepts is spatially inaccurate and cannot be relied upon to definitely designate the right-of-way. See 81 Fed. Reg. 40757, 40758 (June 22, 2016). If PHMSA is to require that MCAs be defined by proximity to roadways, PHMSA must provide an accurate source for this information. AGA also suggests that in the dataset provided by PHMSA, PHMSA consider identifying the roadways through the center line of the roadway in conjunction with a specified buffer on either side.

AGA also suggests the elimination of outside areas from the proposed list of occupied sites and thus from the MCA definition. AGA believes any outside area reasonably intended for public assembly is already captured through the identified sites within HCAs, which includes areas occupied by 20 or more persons at least 50 days a year. As noted below, operators are including within HCAs any site that may have the potential to be occupied by 20 or more persons at least 50 days a year – they are not physically counting individuals and tracking their whereabouts. In fact, each of the examples provided by PHMSA in the Occupied site definition for outside areas (stadiums, playgrounds, etc.) is already captured in HCAs by operators today. Outside areas that are occupied by 5-19 people 50 days a year could be vast, variable, and unclear. Theoretically, any area along a pipeline could meet this criteria and operators would in essence be required to prove that area does not meet this criterion versus identifying those that do.50

Additionally, AGA supports API’s comments that the first criteria within the MCA or occupied site definition should be raised from five buildings to ten. This would keep the criteria consistent with the demarcation within Class 1 locations versus Class 2 locations in §192.5 Class Locations.

As previously mentioned, one justification for the two method approach is to limit the impact of introducing Moderate Consequence Areas into pipeline safety regulations. AGA strongly disagrees with PHMSA’s Preliminary Regulatory Impact Assessment that states:

50 AGA believes that PHMSA has not considered the number of outside areas that could meet this definition nor the resources it would take to literally apply this definition. Operators have no control over individual’s whereabouts, and would therefore need to vigilantly inspect and survey all outside areas within their service territory. In some areas, the average length of a hunting season can exceed 50 days. The routine congregation of a hunting party in a certain location, or the presence of a deer stand or similar structure could result in a newly created MCA. This ad-hoc creation of an MCA cannot be controlled or predicted by the operator.
“Because operators must have already performed analysis in order to have identified HCAs, or verify that they have no HCA, PHMSA assumed that the cost of identifying MCAs is negligible compared to the cost of assessments and did not quantify the cost to identify MCAs.”

This assumption is fundamentally flawed and is incorrect. Today, operators are identifying identified sites, which are defined in §192.903 as:

Identified site means each of the following areas:

(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or

(b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or

(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

As seen in the definition, operators are charged with identifying structures and open areas with 20 or more persons. It is apparent through PHMSA’s comments that PHMSA is assuming that operators are physically counting the individuals at these premises. However, on the contrary, operators are making conservative judgments and capturing any outside area, open structure, or building that may have the potential to be occupied by 20 persons. Operators are not excluding buildings with 19 persons. PHMSA’s proposed definition for “occupied site” would drive operators to physically count the individuals at these sites continuously throughout the year and thus distinguish those sites with four versus five people and nineteen versus twenty. This requirement is a significant administrative, resource, and cost impact that is not being captured in PHMSA’s PRIA.

The currently proposed “occupied site” definition would require this extreme level of granularity and would be overly burdensome to operators. AGA estimates this burden to be approximately $4,600,000 for the initial identification of MCAs and an annual cost of $3,900,000 every year after for maintaining this database. Both of these costs need to be added to the impact assessment if MCAs are maintained in the final rule. Furthermore, PHMSA needs to clarify in the final rule that operators are only expected to perform a MCA analysis on pipelines that meet the qualifier of “able to accommodate inspection by means of an instrumented in-line inspection tool.” It would be unnecessary for an operator to perform this cumbersome analysis on a pipeline that does not meet the applicability of the proposed requirements where MCAs are referenced. Any requirement to do so, including reporting through the Annual Report, will be a true diversion of resources. Operators should be expending those resources on making their pipelines safer and not categorizing them for reporting purposes.

AGA also has significant concerns with several of PHMSA’s statements within the PRIA, such as:

“In addition, there is no data on the extent of mileage that would meet the definition of an MCA.”

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51 PRIA. Page 32.
52 PRIA. Page 10.
and,

“These assumptions were necessary because data for non-HCA segments is limited, and there is no data related to the population of pipelines that could meet the new definition for MCA.”\(^{53}\)

The fact that PHMSA’s Best Professional Judgement (BPJ) for the entirety of this regulatory impact assessment is founded on PHMSA’s inability to quantify the pipeline mileage incorporated into the proposed requirements. AGA believes this nullifies the whole assessment. PHMSA is required to consider the impact of its proposed regulations and must collect the necessary information to make this consideration.

Even more confusing, PHMSA does make an attempt to quantify MCA mileage in Table 3-32 in the PRIA using arbitrary percentages to determine the mileage in Class 3, Class 4, and Class 1 and 2 MCAs.\(^{54}\) PHMSA’s arbitrary estimate of 39,213 miles represents 13% of the total 297,826 onshore transmission pipeline miles. PHMSA estimation of the number of MCA miles in Class 2 locations is 50% of the total Class 2 miles outside HCAs.\(^{55}\) AGA’s Method 1 approach would capture 100% of the Class 2 miles outside HCAs. Additionally, PHMSA is only estimating 2% of Class 1 pipeline miles to be captured through their proposed MCA definition.

Through a survey of the membership, AGA estimates the number of pipeline miles for AGA membership located in Class 3, Class 4, and MCAs to be 10% for Method 1 and 15% for Method 2, as proposed by PHMSA. Even lowering total pipeline miles captured through AGA’s Method 2 approach, due to AGA’s proposed changes, AGA is confident that the number of miles captured will remain comparable to PHMSA’s estimate of 13%.

PHMSA’s proposed MCA concept and requirements are rooted in the Congressional mandate that PHMSA evaluate whether gas transmission integrity management program requirements, or elements thereof, should be expanded beyond HCAs and whether applying integrity management program requirements to additional areas would mitigate the need for class location requirements. See Pub. L. No. 112-90. As noted in Section III.A, PHMSA was required to include its findings in a report to Congress. Within Section 5, Congress expressed its clear desire to be able to review the report before PHMSA initiated any rulemakings. This report was not provided to Congress in the timeframe mandated in the 2011 Act. In addition, the report was only provided to the public on June 9, 2016; two days after the comment period on the Proposed Rule was initially scheduled to close. Furthermore, nowhere does PHMSA describe or justify the approach it has taken to develop the MCA definition. Specifically, PHMSA has offered no justification or explanation for its definitions of occupied site or how it applies the potential impact circle as related MCAs. A critical question left open is how PHMSA reached the proposed definition of MCA.

Another consideration for PHMSA is a qualifier within the MCA definition that the MCA definition only applies to pipelines operating greater than 30% SMYS. There is a long documented history on why pipelines that operate greater than 30% SMYS pose a larger risk to the public than those operating less than 30%. Pipelines that operate less than 30% SMYS are prone to fail by leakage rather than rupture. This understanding is so widely accepted that Congress enacted specific mandates to pipelines that operate greater than 30% SMYS.\(^{57}\) It is additionally supported by the Kiefner/GTI Report “Leak vs. Rupture Thresholds for Material and Construction

\(^{53}\) PRIA. Page 32.
\(^{54}\) PRIA. Page 53.
\(^{55}\) PRIA. Page 53.
\(^{56}\) The approximation for Method 2 is with PHMSA’s proposed MCA definition, not with AGA’s proposed changes.
\(^{57}\) Pipeline Safety Act of 2011. Section 23(d).
Anomalies,” that pointed out that “no evidence was found in propagating ductile rupture could arise from an incident attributable to any one of these causes in a pipeline that is being operated at a hoop stress level of 30% of SMYS or less.” This distinction is supported by PHMSA in the preamble of this Proposed Rule. Qualifying that MCAs are to only applicable to pipelines that operate greater than 30% SMYS would allow operators to focus on those high risk pipelines for both MAOP Verification (§192.624) and Pipeline Assessments (§192.710).

Finally, AGA has several comments pertaining to the application of MCAs and the qualification within the Proposed Rule that the requirements for assessments and MAOP Verification in MCAs be limited to those pipelines that “can accommodate inspection by means of instrumented inline inspection tools (i.e., “smart pigs”).” These comments are within Section IV.A.3: MAOP Verification, Section IV.D: Subpart Q, and Section IV.C: Definitions – “Able to Accommodate Inspection by means of an ILI Tool” of these comments.

AGA proposes the following two method approach for the identification of MCAs:

*Moderate consequence area* means an onshore area established by one of the methods described in paragraphs (1) or (2) as follows for pipelines operating at greater than 30% SMYS:

1. An area classified as –
   a. A Class 2 location under §192.5; or
   b. A Class 1 location that is within a potential impact circle, as defined in §192.903 containing the existing edge of pavement for a designated interstate, freeway, or expressway, and other principal arterial roadway of 4-lanes or more as defined in the Federal Highway Administration’s *Highway Functional Classification Concepts, Criteria, and Procedures*.
   c. Does not meet the definition of high consequence area as defined §192.903.

2. The area that is within a potential impact circle, as defined in §192.903, containing –
   a. five (5) Ten (10) or more buildings intended for human occupancy; or
   b. An outside area or open structure that is occupied by five (5) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive). Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility, or
   c. an occupied site a non-residential building intended for human occupancy that is occupied by less than twenty persons five (5) or more persons at least five (5) days a week for ten (10) weeks in any twelve (12)—month period. (The days and weeks need not be consecutive). Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or
   d. a right-of-way The existing edge of pavement for a designated interstate, freeway, or expressway, and other principal 4—lane arterial roadway of 4-lanes or more as defined in the Federal Highway Administration’s *Highway Functional Classification Concepts, Criteria and Procedures*.
   e. Does not meet the definition of high consequence area as defined in §192.903.

3. Where a potential impact circle is calculated under method (1) or (2) to establish a moderate consequence area, the length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an occupied site a non-

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residential building intended for human occupancy that is occupied by less than twenty persons or more persons at least 5 days a week for 10 weeks in any 12-month period, five (5) or ten (10) or more buildings intended for human occupancy, or a right-of-way the existing edge of pavement for a designated interstate, freeway, or expressway, or other principal 4-lane arterial roadway of 4-lanes or more, to the outermost edge of the last contiguous potential impact circle that contains either an occupied site a non-residential building intended for human occupancy that is occupied by less than twenty persons or more persons at least 5 days a week for 10 weeks in any 12-month period, five (5) or more buildings intended for human occupancy, or a right-of-way existing edge of pavement for a designated interstate, freeway, or expressway, or other principal 4-lane arterial roadway of 4-lanes or more as defined in the Federal Highway Administration’s Highway Functional Classification Concepts, Criteria, and Procedures.

C. Definition of Able to Accommodate Inspection by Means of an Instrumented In-Line Inspection Tool

In the Proposed Rule, PHMSA has placed a qualifier on the transmission pipelines applicable to new requirements in Moderate Consequence Areas (MCAs): MAOP Verification (§192.624) and Pipeline Assessments Outside of HCAs (§192.710 or Subpart Q in AGA’s proposal). The qualifier limits application of the new MCA requirements to pipeline segments that “can accommodate inspection by means of instrumented inline inspection tools (i.e. ‘smart pigs.’)” AGA understands, through review of the Office of Management and Budget (OMB) redline of the Proposed Rule, that this qualifier was added during the cost/benefit analysis and discussions with OMB. AGA therefore infers that this qualifier was intended to reduce the mileage covered by MCAs and increase the percentage of pipelines that would utilize in-line inspection as the assessment method for §192.710, which ultimately reduces the overall cost of complying with the Proposed Rule. This assumption is further addressed in AGA’s comments on the PRIA.

For regulatory certainty and clarity, AGA, along with the other trade associations, believe it is necessary for PHMSA to introduce a new definition in §192.3, Pipelines that can accommodate inspection by means of an instrumented in-line inspection tool. Providing the criteria that a pipeline must meet to be placed into this category will remove uncertainty and inconsistency in determining which pipelines meet PHMSA’s qualifier, and therefore which transmission lines are subject to the requirements of §192.624 and §192.710.

AGA believes there are five critical features that a pipeline or in-line inspection tool must achieve in order to meet PHMSA’s intent for this qualifier. Three of the five features mirror the instructions found for the Gas Transmission Annual Report, Part R – Gas Transmission Miles by Pressure Test (PT) Range and Internal Inspection, which states: “Miles Internal Inspection Able” means a length of pipeline through which commercially available devices can travel, inspect the entire circumference and wall thickness of the pipe, and record or transmit inspection data in sufficient detail for further evaluation of anomalies.”

AGA provides support for each of the criteria included in AGA & INGAA’s proposed definition:

1. **The tool must be free-swimming.**

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There are numerous ILI solutions available on the market today; however, not all of them are free swimming. Free swimming is an industry term that corresponds to the tool’s ability to traverse a pipeline using the flow of natural gas during normal operations, without venting or flaring of gas to achieve required flow rates and/or pressure differentials, and without additional forces to propel the tool, such as a robotic platform or a tethered solution. The other ILI platforms are significantly more complicated and expensive to deploy than free-swimming ILI tools and, in the PRIA, PHMSA did not account for the added cost considerations for the specific use of these more complicated ILI platforms.

2. **The tool must be commercially available.**
AGA believes in order for a tool to meet the criteria within the definition and PHMSA’s intent, the tool must be commercially available and readily available for operators. This criterion would avoid any forced application of tools that are still being tested and researched by ILI vendors or research organizations. Once an innovative solution is developed and fully deployed for commercial use, it would then meet the definition proposed by AGA.

3. **The tool must be able to inspect the entire circumference of the pipeline**
Some transmission pipelines are unable to accommodate a free-swimming in-line inspection tool and the limiting factor is due to the physical configuration or constraints in the pipeline system. In other cases, the limitation is the lack of an adequate, consistent and predictable gas flow through the pipeline or sufficient pressure differential necessary to overcome the friction forces on the pipe wall and propel the ILI tool, a necessary requirement during in-line inspection.

4. **The tool must be able to capture and record or transmit relevant, interpretable inspection data.**
Some transmission pipeline configurations are complex with multiple, consecutive bends and elbows, which may prevent a tool from being able to gather meaningful data. AGA believes pipelines where a commercially available free-swimming ILI tool can successfully travel through a pipeline but cannot gather meaningful data due to system configuration constraints do not meet PHMSA’s intent for a pipeline that can accommodate inspection by ILI. In these situations, an operator would have to use another means besides in-line inspection to perform the requirements within §192.710 and §192.624, thus negating PHMSA’s intended benefit of using an ILI solution.

5. **The pipeline must not need additional permanent modifications to accommodate passage of the tool**
Without this criterion, AGA is concerned that regulators may attempt to define any pipeline as “able to accommodate inspection by means of an ILI tool.” This criterion ensures that no misapplication of the “smart pig” qualifier occurs. Once an operator replaces any inline fittings (e.g. tees, elbows, reduced port valves, etc.) that might prevent the pipeline from being able to utilize in-line inspection, and can also satisfy the other criteria contained in 1-4 above, then both the operator and regulator can agree to define that the transmission pipeline is “able to accommodate inspection by means of an instrumented in-line inspection tool.”

Using each of these criteria, AGA suggests adding the following definition in the Final Rule, which is consistent with the proposed definitions from the other trade associations.

**Pipelines that can accommodate inspection by means of instrumented inspection tool** - means a length of pipeline through which a free-swimming, commercially available ILI tool can travel (using flow and
pressure conditions encountered in normal operations), inspect the entire circumference of the pipe, capture and record or transmit relevant, interpretable inspection data in sufficient detail for further evaluation of anomalies without the need for additional permanent physical modifications to the pipeline.

D. Reliability Assessments Outside of HCAs (AGA’s Proposed Subpart Q)

As highlighted in the introduction of these comments, AGA has a long standing commitment to “expand integrity management principles beyond High Consequence Areas (HCAs).” While AGA has proposed an alternative solution in Section III.F of these comments, AGA does support the intent behind PHMSA’s proposed §192.710 Pipeline Assessments, and believes that it is feasible for operators to implement. Many natural gas operators already perform assessments on these categories of transmission pipelines. While AGA accepts that codifying the assessment requirement is reasonable, AGA does not agree that this requirement should be placed in Subpart M: Maintenance of 49 C.F.R. 192.

To assist in full recognition of what is required when planning for pipeline assessments, a clear and concise set of requirements should be codified that minimizes regulatory uncertainty. As written, §192.710 is loosely defined and will cause multiple interpretations to be made by operators, state commissions, and PHMSA inspectors. This could result in incorrectly applied actions by operators and inspectors that do not meet the original intent of the proposed requirements. AGA is proposing that PHMSA create a new subpart specifically for the additional assessment requirements. The new subpart will improve clarity for operators through the proposed requirements identified in §192.710. If PHMSA agrees with this approach the following proposed Sections will need to reflect the new subpart reference. AGA has provided new references in each of these sections in Appendix A of these comments.

For PHMSA’s consideration, AGA provides in these comments a proposed Subpart “Q” Reliability Assessments for Transmission Lines Outside of High Consequence Areas. This new subpart will provide clarity and minimize regulatory uncertainty to the full scope of assessment requirements. The comments for this section only apply to AGA’s proposal for a new Subpart. Please see the remainder of AGA’s comments for specific topics that are simply references within this section, such as Moderate Consequence Areas (Section IV.B of these comments) and Use of Direct Assessments (Section IV.E.2 of these comments).

AGA’s proposed Subpart has twelve sections. The sections include:
§192.1101 - What do the regulations in this subpart cover?
§192.1103 - What definitions apply to this subpart?
§192.1105 - How does an operator identify an Assessment Segment?
§192.1107 - What must an operator do to implement this subpart?
§192.1109 - What assessment methods can an operator use?
§192.1111 - What can an operator do for a low stress assessment?
§192.1113 - What actions must be taken to address imperfections and damages?
§192.1115 - What does an operator do when a new pipeline segment is subject to this subpart?
§192.1117 - When can an operator deviate from assessment or reassessment intervals?
§192.1119 - How is the threat of manufacturing and construction defects addressed on the pipeline?
§192.1121 - What records must an operator keep?
Each of these sections proposes additional, essential details that AGA believes was not provided or addressed in PHMSA’s proposed §192.710. Providing detail through the creation of a new, unique subpart gives all stakeholders the ability to determine assessment requirements and expectations clearly. AGA’s comments provide the scope, breadth, and justification for each section of the proposed Subpart Q.

§192.1101 - What do the regulations in this subpart cover?
The proposed section “What do the regulations in this subpart cover?” provides stakeholders a clear understanding of what pipelines are affected by the extended assessment requirement. In addition, the section clearly states that the new subpart does not apply to HCAs as defined in §192.903. Providing this clear distinction will provide all stakeholders with assurance that Class 3, Class 4, and MCAs that can accommodate inspection by means of instrumented inline inspection tools are to be managed separately from HCAs as defined in §192.903.

§192.1103 - What definitions apply to this subpart?
The proposed subpart provides stakeholders a definition section with clear explanations of the unique terminology used within the subpart. Specifically, AGA has introduced the term “assessment segment” to function similarly to “covered segment” in Subpart O. AGA has also introduced a criterion within the assessment segment definition that would allow operators to apply the requirements of Subpart Q to pipelines not located in Class 3, Class 4 or MCAs. This allows those operators to perform additional measures on pipelines they determine to be high risk, but are outside PHMSAs defined areas.

§192.1105 - How does an operator identify an Assessment Segment?
The section “How does an operator identify an Assessment Segment?” provides stakeholders with a clear understanding that there is an identification activity that must be followed to ensure compliance with the regulation.

§192.1107 - What must an operator do to implement this subpart?
Section §192.1107, What must an operator do to implement this subpart?, provides a dedicated section describing the allotted assessment timelines previously outlined by PHMSA. AGA did not propose a change in timelines; however, AGA is proposing a clear distinction of the timelines by dedicating a subpart section to highlight its importance. The section also has a requirement for an assessment plan. The proposed §192.710 makes no mention of an assessment plan and this component of managing assessments on Class 3, Class 4, and MCAs seems to be implied in PHMSA’s proposed language. Providing a requirement for an assessment plan directly in the proposed subpart eliminates regulatory uncertainty by providing all stakeholders with clear expectations and a framework for managing required assessments.

§192.1109 - What assessment methods can an operator use? & §192.1111 - What can an operator do for a low stress assessment?
Section §192.1109, What assessment methods can an operator use?, includes seven of the eight methods proposed in §192.710. The final method, low stress assessment, is being proposed as its own unique section of the subpart, §192.1111. The proposed section provides distinction from other assessment methodologies and provides a unique section dedicated to pipelines where a low stress assessment is applicable. It should be noted that in the existing Subpart O, the ability to conduct low stress assessments is available, but not required.
Operators may choose to use standard assessment methods for all pipelines, avoiding the low stress assessment activities. The proposed §192.710 stated that an operator must follow the low stress assessment method for MAOP less than 30% SMYS. AGA recommends modifying the requirement of “must” to “may” following the same assessment structure provided by Subpart O.

Additionally, within §192.1109, AGA proposes a modification to the Direct Assessment method. The proposed §192.710 includes:

*Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess (due to low operating pressures and flows, lack of inspection technology, and critical delivery areas such as hospitals and nursing homes) using the methods specified in paragraphs (a)(1) through (a)(5) of this section.*

AGA suggests that this sentence be completely deleted from the direct assessment section as PHMSA provides no technical justification for this limitation. As mentioned in our comments on Direct Assessment, creating regulatory requirements based on opinions and preference is not reasonable and denies operators a valuable assessment method. See AGA’s comments on Direct Assessment in Section IV.E.2.

§192.1113 - What actions must be taken to address imperfections and damages?

As discussed in Section IV.F of these comments, AGA proposes to move the PHMSA proposed §192.713 for imperfections and damages found during assessments outside HCAs into the proposed Subpart Q §192.1113.

§192.1115 - What does an operator do when a new pipeline segment is subject to this subpart?

With PHMSA’s proposed §192.710, operators would have been left uncertain about regulatory requirements, specifically assessment compliance times, for newly identified pipelines that met the applicability of §192.710. Therefore, AGA suggests a straightforward addition to the requirements that a newly identified pipeline needs to receive an assessment within 15 years. This proposes requirement mirrors §192.921(f) and (g) within Subpart O.

§192.1117 - When can an operator deviate from assessment or reassessment intervals?

Section §192.1117, When can an operator deviate from assessment or reassessment intervals?, provides stakeholders with a clear description of when deviation from assessments can be considered. AGA’s proposal provides deviation reasons that are consistent with those provided in Subpart O - §192.943, except for the second criterion that AGA has proposed:

(2) Inability to perform scheduled assessments or reassessments required by this subpart due to significant unplanned changes in the Subpart O assessment schedule. To justify this, the operator must demonstrate that the additional Subpart O work contains the following:

(i) Has a significantly higher priority than and takes precedence over the Subpart Q;
(ii) All scheduled work cannot be done within the timeframe specified, and
(iii) This work cannot have been anticipated with sufficient advance notice by the operator.

AGA recognizes that HCAs and Subpart O refer to the most critical pipelines for public safety. As such, operators require the ability to delay assessment work required under Subpart Q due to unforeseen circumstances that may arise which limits an operator’s ability to perform both HCA assessments under Subpart O and additional
assessments under Subpart Q. AGA asserts that the Subpart O criteria take precedence in these instances which may include assessments associated with the identification of a new threat within Subpart O or a new weather-related concern that requires an immediate additional assessment. These comments apply whether PHMSA adopts AGA’s proposal for a Subpart Q or if these requirements remain within the proposed §192.710.

§192.1119 - How is the threat of manufacturing and construction defects addressed on the pipeline?
AGA believes there are two elements of pipeline reliability that should be explicitly addressed for pipelines located in Class 3, Class 4 and MCA locations within AGA’s proposed Subpart Q: the stabilization of manufacturing and construction defects, and addressing cracks on pipelines. This is consistent with AGA’s comments on MAOP Verification and AGA’s proposed alternative solution, highlighted in Sections III.F and IV.A.3 of these comments. AGA also provides workable solutions for addressing manufacturing and construction threats in Section IV.E.3 of these comments on Risk Assessments & Models for HCAs and suggests a mirrored approach for pipelines in MCAs, Class 3, and Class 4 locations. Pipelines that have experienced a reportable in-service incident as defined in §192.3, since its most recent successful Subpart J pressure test, due to an original manufacturing-related defect, a construction-installation, or fabrication-related defect, or cracking related defect will perform an assessment consistent with those listed in §192.624(c) as proposed in §192.917(e)(3) for HCAs. AGA proposes that this requirement applies to both historical incidents, as identified through records publicly available from PHMSA, and for incidents that may occur in the future. In AGA’s proposal, operators will have one year to incorporate that pipeline into their reliability plan and fifteen years to perform the assessment, commensurate with proposed §192.1107.

AGA proposes that an operator’s obligation to address historical incidents should be directly linked to those incidents that have records publicly available through PHMSA. AGA is concerned with the potential difficulty in identifying these past incidents. Operators are under no obligation to maintain records of incidents that would detail the specificity of the incident to determine whether the incident and pipeline were subject to the proposed requirements. Aside from this fact, due to mergers and acquisitions, as well as the age of the pipeline, these records may be simply unavailable. AGA suggests that the regulations refer to the PHMSA website that contains all federally-reportable incidents as the data source to determine applicability of §192.1119 and §192.917(e)(3) for identifying pipeline segments that experienced a reportable in-service incident as defined by §191.3. Including such a reference will clearly identify past incidents and would provide clarity and certainty in identify those future incidents that would require more stringent assessment methods.

§192.1121 - What records must an operator keep?
Section §192.1121, What records must an operator keep?, provides stakeholders with regulatory certainty on the Subpart Q applicable records that are required for assessments segments. This section serves the same function as §192.947 in Subpart O.

AGA is hopeful that PHMSA understands AGA’s thoughtful and reasonable intent behind proposing this new section to provide additional clarity and regulatory certainty to PHMSA’s proposals. Below is AGA’s proposal for the new Subpart Q:

Subpart Q – Reliability Assessments Outside of High Consequence Areas

§192.1101 What do the regulations in this subpart cover?
This subpart prescribes the assessment requirements for steel transmission lines located in Class 3 and 4 locations or steel pipeline segments that are located in moderate consequence areas (MCAs) that can accommodate inspection by means of instrumented inline inspection tools (i.e., “smart pigs”) as defined in §192.3.

This subpart does not apply to pipeline segments located in a High Consequence Areas as defined in §192.903.

§192.1103 What definitions apply to this subpart?

Assessment Segment means a pipeline segment located in one of the following locations that is not meeting all the requirements of Subpart O of this part:

(a) A non-HCA Class 3 location under §192.5; or
(b) A non-HCA Class 4 location under §192.5; or
(c) A moderate consequence area as defined in § 192.3, if the pipeline can accommodate inspection by means of instrumented inline inspection tools (i.e., “smart pigs”); or
(d) A non-HCA pipeline, not located in one of the previous locations, that the operator chooses to include in Subpart Q based on the risk analysis of their system.

Moderate consequence area – This term is defined in §192.3.

§192.1105 How does an operator identify an Assessment Segment?

To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify class 3 and 4 locations and moderate consequence areas. An operator must follow the definitions of a moderate consequence area in §192.3 when identifying moderate consequence areas.

§192.1107 What must an operator do to implement this subpart?

(a) No later than [insert date 1 year after the effective date of the final rule], an operator of a pipeline segment subject to this subpart must develop and follow a written assessment plan. The assessment plan must consist, at a minimum, of a framework that describes the process of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and for performing each assessment. An operator must review the plan periodically and make improvements as appropriate.

(b) Initial assessment - No later than [insert date that is 15 years after the effective date of the final rule] an operator must perform initial assessments.

(c) Subsequent assessments - No later than 20 years after an initial or subsequent assessment of a segment, an operator must perform a subsequent assessment. A shorter reassessment interval may be required based upon the type of anomaly, material, operational conditions and environmental conditions affecting the pipeline segment, or as otherwise necessary to ensure public safety.

(d) Prior assessment. An operator may use a prior assessment conducted before [Insert effective date of the final rule] as an initial assessment for the segment, if the assessment meets any the requirements of 192.1113. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (c) of this section.

(e) MAOP Verification. An operator may use assessment methods conducted in accordance with the requirements of §192.624(c) for verification of MAOP to meet the requirements of this subpart.
§ 192.1109 What assessment methods can an operator use?
The initial and the subsequent assessments required by § 192.1107 must be performed using one or more of the following methods:

(a) Internal inspection tool or tools capable of detecting the appropriate threats in accordance with § 192.493;
(b) Pressure test conducted in accordance with subpart J of this part. The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, manufacturing and related defect threats, including defective pipe and pipe seams, dents and other forms of mechanical damage;
(c) “Spike” hydrostatic pressure test in accordance with § 192.506;
(d) Excavation and in situ direct examination by means of visual examination and direct measurement and recorded non-destructive examination results and data needed to assess applicable threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI);
(e) Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F;
(f) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in § 192.925, 192.927 or 192.929; or
(g) Other technology or technologies that an operator demonstrates can provide an equivalent understanding of the line pipe for each of the threats to which the pipeline is susceptible.

§192.1111 What can an operator do for a low stress pipeline assessment?
For pipeline segments with MAOP less than 30% of the SMYS, in lieu of the requirements within §192.1109, an operator may assess for the threats of external and internal corrosion, as follows:

(a) External corrosion. An operator must take one of the following actions to address external corrosion on a low stress segment:
   (1) Cathodically protected pipe. To address the threat of external corrosion on cathodically protected pipe, an operator must perform an indirect assessment (i.e. indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) at least once every twenty years on the segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the segment. This evaluation must consider, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
   (2) Unprotected pipe or cathodically protected pipe where indirect assessments are impractical. To address the threat of external corrosion on unprotected pipe or cathodically protected pipe where indirect assessments are impractical, an operator must—
      (i) Conduct leakage surveys as required by § 192.706 at 4-month intervals; and
      (ii) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(b) Internal corrosion. If an operator determines that internal corrosion is a threat on a low stress segment, an operator must—
   (1) Conduct a gas analysis for corrosive agents at least twice each calendar year;
   (2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a segment; and
(3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (ii)(A)-(ii)(B) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

§ 192.1113 What actions must be taken to address imperfections and damages?

(a) General. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made so as to prevent damage to persons, property, or the environment. Operating pressure must be at a safe level during repair operations.

(1) Temporary pressure reduction. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, see §192.7); AGA Pipeline Research Council, International, PR-3-805 (R-STRENG) (incorporated by reference, see §192.7) to determine the safe operating pressure that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. Pipe and material properties used in the remaining strength calculation must be documented in traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based in accordance with §192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgements may be used. An operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement or an intrastate covered segment is regulated by that State.

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

(b) Repair. Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe; or

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(c) Schedule for evaluation and remediation. An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (e) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. If an
operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) Remediation schedule. For pipelines not located in high consequence areas, an operator must complete the remediation of a condition discovered after [the effective date of the rule] according to the following schedule:

(1) High priority conditions. An operator must confirm and repair the following conditions immediately upon discovery:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in §192.7(c). Pipe and material properties used in remaining strength calculations must be documented in traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with §192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgments may be used.

(ii) A dent that has any indication of metal loss due to a scratch, a gouge, cracking or a stress riser.

(iii) Metal loss greater than 80% of nominal wall regardless of dimensions.

(iv) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency or high risk high frequency electric resistance welding or by electric flash welding.

(v) Any indication of significant stress corrosion cracking (SCC).

(vi) An indication of metal loss greater than or equal to 20% of nominal wall selectively affecting a detected longitudinal seam other than those seam types listed in §192.1113(d)(1)(iv).

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

(2) Until the remediation of a condition specified in paragraph (d)(1) is complete, an operator must reduce the operating pressure of the affected pipeline to the lower of:

(i) A level that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, determined using ASME/ANSI B31G (“Manual for Determining the Remaining Strength of Corroded Pipelines” (1991) or AGA Pipeline Research Committee Project PR-3-805 (“A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe” (December 1989)) (“RSTRENG,” incorporated by reference, see § 192.7) for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, and crack-related defects, appropriate failure criteria and justification of the criteria must be used. If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by traceable, verifiable, and complete records, then the operator must determine the material properties based upon the material documentation program specified in §192.607. Until such time that the requirements
within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgments may be used; or

(ii) 80% of pressure at the time of discovery.

(3) **Two-year conditions.** An operator must confirm and repair the following conditions within two years of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) 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 longitudinal or helical (spiral) seam weld.

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

(iv) A gouge or groove greater than 12.5% of nominal wall.

(v) Any indication of a crack or crack-like defect other than an immediate condition.

(vi) An indication of metal loss less than 20% of nominal wall selectively affecting a detected longitudinal seam other than those seam types listed in §192.1113(d)(1)(iv).

(vii) A dent that has any indication of metal loss due to corrosion.

(4) **Monitored conditions.** An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and reliability assessments for any change that may require remediation:

(i) 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).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% 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.

(e) **In situ direct examination of crack defects.** Operators must perform direct examination of known locations of cracks or crack-like defects using inverse wave field extrapolation (IWEX), phased array, automated ultrasonic testing (AUT), or equivalent technology that has been validated to detect tight cracks (equal to or less than 0.008 inches). In-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts in direct examination inspection for accuracy for the type of defects and pipe material being evaluated.

§ 192.1115 What does an operator do when a new pipeline segment is subject to this subpart?
A newly identified assessment segment must be incorporated into the assessment plan within one year of identification. An initial assessment of the newly identified segment is required within 15 years of being identified.

§ 192.1117 When can an operator deviate from assessment or reassessment intervals?
(a) **Waiver from assessment or reassessment interval in limited situations.** In the following limited instances, OPS may allow a waiver from an assessment or reassessment interval if OPS finds a waiver be consistent with pipeline safety.

(1) **Lack of internal inspection tools.** An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the reliability of the pipeline segment.

(2) **Inability to perform scheduled assessments or reassessments required by this subpart due to significant unplanned changes in Subpart O assessment schedule.** To justify this, the operator must demonstrate that the additional Subpart O work contains the following:
   (i) Has a significantly higher priority than and takes precedence over the Subpart Q;  
   (ii) All scheduled work cannot be done within the timeframe specified, and  
   (iii) This work cannot have been anticipated with sufficient advance notice by the operator.

(3) **Maintain product supply.** An operator may be able to justify a longer assessment or reassessment period for a pipeline segment if the operator demonstrates that it cannot maintain local product supply if it conducts the assessment or reassessment within the required interval.

(b) **How to apply.** If one of the conditions specified in paragraph (a)(1), (a)(2), or (a)(3) of this section applies, an operator may seek a waiver of the required assessment or reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required assessment or reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.

§ 192.1119 How is the threat of manufacturing and construction defects addressed on the pipeline?

**Manufacturing and construction defects.** An operator must analyze the assessment segment to determine the risk of failure from manufacturing and construction defects (including seam defects) in the assessment segment. The analysis must consider the results of prior assessments on the assessment segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to a pressure test satisfying the criteria of subpart J of at least 1.25 times MAOP, or has been subjected to a pressure reduction of 1.25 times the highest documented operating pressure, or has been assessed by an in-line inspection tool qualified to detect defects that would fail a pressure test of 1.25 times the highest documented operating pressure, and the segment has not experienced a reportable in-service incident attributed to a manufacturing or construction defect as identified through publicly available records from PHMSA. If the manufacturing or construction defects cannot be confirmed as stable, remediation of the threat will be completed in accordance with the schedule provided in §192.624(b). If any of the following changes occur in the assessment segment, an operator must prioritize the assessment segment as a high risk segment for the baseline assessment or a subsequent reassessment, and must reconfirm or reestablish MAOP in accordance with §192.624(c).

(a) The segment has experienced a reportable in-service incident as defined in §191.3 due to a manufacturing-related defect, a construction-, installation-, or fabrication-related defect as identified through publicly available records from PHMSA.

(b) MAOP increases; or

(c) The stresses leading to cyclic fatigue increase.
§ 192.1121 What records must an operator keep?

An operator must maintain records demonstrating compliance with the requirements of this subpart for the life of the pipeline.

**E. 49 C.F.R. Part 192 - Subpart O Changes**

1. Transmission Integrity Management Program Preventative & Mitigative Measures

PHMSA has proposed several amendments to §192.935: *What additional preventative and mitigative measures must an operator take?*, making the requirements very prescriptive and adding specific Preventative & Mitigative (P&M) requirements for internal corrosion and external corrosion. When the initial Transmission Integrity rule was issued, P&M measures were intended to be supplemental risk-reducing actions taken by an operator, beyond those already required by Part 192, to augment integrity assessments being performed in HCAs, and to provide added protection to low-stress pipelines in Class 3 & 4 locations outside of HCAs. AGA supports regulations that reflect the reality that operators knew their system the best, and that operators are in the best position to determine which P&M measures have the greatest potential to enhance safety on their system. Fundamentally, P&M measures are intended to focus resources to address critical threats to the covered pipeline segment, not blanket mandates. The Proposed Rule contains proposed language which contradicts this philosophy and fails to recognize that each system is unique and therefore should have distinct integrity management plans that prioritizes risk to apply resources where they will have the greatest impact. AGA is supportive of PHMSA’s attempt to provide some additional guidelines around the selection of P&M measures to be applied by the operator; however, AGA has concerns with the proposed changes to §192.935.

As written, the proposed language prescriptively requires operators to perform all of the listed P&M measures within §192.935(a). This is contrary to everything integrity management was intended to do – place resources where they will have the greatest impact for improving pipeline safety. AGA believes one portion of the modified regulatory language effectively implements the intent of integrity management, “such measures must be based on the risk analysis required by §192.917”. The second addition to this sentence, however, “… and must include, but are not limited to:” completely changes the regulatory requirement and negates the need for an operator to do a risk analysis. In essence, this regulatory language suggests that every operator must perform each of the listed actions on every covered pipeline segment within their system regardless if conditions warrant additional measures, or if past efforts have been taken. The list of P&M measures included in the proposed regulation are the following:

1. Correction of the root cause of past incidents to prevent reoccurrence
2. Establishing and implementing adequate operations and maintenance processes that could increase safety
3. Establishing and deploying adequate resources for successful execution of preventative and mitigative measures
4. Installing Automatic shut-off Valves or Remote Control Valves
5. Installing pressure transmitters on both sides of automatic shut-off valves and remote control valves that communicate with the pipeline control center
6. Installing computerized monitoring and leak detection systems
7. Replacing pipe segments with pipe of heavier wall thickness or higher strength
(8) Conducting additional right-of-way patrols
(9) Conducting hydrostatic tests in areas where material has quality issues or lost records
(10) Tests to determine material mechanic and chemical properties that are needed to assure integrity or substantive MAOP evaluations including material property test from removed pipe that is representative of the in-service pipe.
(11) Re-coating of damaged, poorly performing or disbonded coatings.
(12) Applying additional depth-of-cover surveys at roads, streams, and rivers
(13) Remediating inadequate depth-of-cover
(14) Providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

AGA questions if PHMSA’s intent was to prescriptively require the first three in the list, but offer the remainder as simply suggestions for further P&M measures. During the June 2016 PHMSA Pipeline Advisory Committee Meeting and on the subsequent webinars PHMSA held on the Proposed Rule, PHMSA stated that the P&M list contains suggestions of measures operators should consider to enhance pipeline safety. This is not how the regulatory text reads, however. Further confusion results from the language within the PRIA. “The Proposed Rule would expand the listing of example P&M measures. Examples serve to promote awareness of the range of actions an operator could consider, but not constitute as new or different requirements.”

If PHMSA misspoke in all of the above listed forums and this list as a series of mandates where operators must take actions for each measure, AGA provides the following comments on a selection of the listed P&M measures.

(4), (5) & (6) PHMSA has indicated in several forums that Leak Detection Systems, Automatic Shut-off Valves and Remote Control Valves, and any auxiliary equipment will be addressed through a separate rulemaking. AGA believes it is inappropriate to introduce this new requirement pertaining to these P&M measures within this proposed rule due to the complexity of the issue.

(9) & (10) Both of these P&M measures are so closely linked to the proposed requirements within §192.607 and §192.624 that AGA believes their inclusion within §192.935 will ultimately cause additional regulatory confusion and uncertainty. Additionally, AGA reminds PHMSA that HCA pipelines are subject to both of these new regulatory sections in the Proposed Rule, therefore these P&M measures would ultimately be redundant. AGA suggests removing them from the list.

A seemingly minor, yet important, proposed change within §192.935(b)(2): Outside force damage is PHMSA’s reference “geospatial, GIS” when listing measures to minimize consequences of outside force damages to covered segments. This reference is unclear and “geospatial GIS” does not have a causal relationship with outside force damage. Moreover, AGA wants to remind PHMSA that GIS or geospatial information systems are not universally used and are not mandated in 49 C.F.R. 192. Until industry and regulators have had a robust discussion about what constitutes a GIS and how they should be applied, AGA opposes any reference to GIS within pipeline safety regulations.

61 PRIA. Page 74.
Also within §192.935, PHMSA introduces new regulatory requirements when an operator “gains information about” internal or external corrosion. See §192.935(f) and §192.935(g) respectively. AGA believes this proposed requirement is overly broad, and in an extreme situation, could imply that an operator is required to implement an internal or external corrosion program simply because they read about internal corrosion in an industry paper or by attending a technical conference. AGA believes that specifically stating that the operator “finds evidence of the potential for” internal or external corrosion eliminates any unintended applications of PHMSA’s proposed requirements. See Appendix A of these comments for AGA’s suggested modification to the proposed regulatory language.

Additionally, the qualifier “on the pipeline” needs to be added to the regulatory language. Pipeline systems are diverse and sometimes noncontiguous, and operate under varying operational conditions. Evidence of internal corrosion on one part of a system does not warrant the implementation of an internal corrosion program in a completely separate part of the system where physical and environmental conditions may be different.

As currently written, §192.935(g)(2) is requiring the integration of results from “indirect assessment” (CIS and DCGV or ACVG) of covered segments with the results of “integrity assessments” which implies duplicate assessments must be completed for segments using ECDA as an assessment method. This would result in redundant efforts and expenses to gain the same information that is already obtained in the integrity assessment for segments using Direct Assessment methods. It should also be noted that these sections seem very redundant to the requirements within §192.465 External corrosion control: Monitoring and §192.478 Internal corrosion control: Onshore transmission monitoring and mitigation, thereby creating the potential for regulatory uncertainty in the application of the proposed regulatory language.

Additionally, in §192.935(g)(1), PHMSA has introduced a requirement that operators control electrical interference currents that can adversely affect cathodic protection. This requirement relies upon operators gaining proprietary information from the local electrical transmission operators operating near a pipeline. Where there is an integrated utility, the sharing of transmission operating parameter may be a non-issue. However, many natural gas utilities operators are not integrated utilities and may not have access to electrical transmission data that is proprietary. The rulemaking assumes that the natural gas operator has access to data to discern the location of electrical transmission lines operating at or above 69 kVA. This is not always the case and as such, the regulation should be less prescriptive and allow operators to perform testing when they gain evidence of potential electrical interference situations versus attempting to prescriptively require natural gas pipeline operators to inspect near the assets of electrical transmission companies who may be unwilling to share operational and positional data.

Also addressed in this proposed rule are slight modifications to §192.935(d): Pipelines operating below 30% SMYS. AGA would like to point out an area of inconsistency that results from the proposed modifications to this section. Pipelines outside of HCAs are currently subject to §192.706 Transmission lines: Leakage surveys. This section requires “leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year.” However, if the pipeline segment has been inspected internally through the use of ILI, this same assessed pipeline has a more rigorous leak survey interval of “semi-annually”. AGA has attempted to address this incorrect prioritization with the following changes to §192.935(d)(3):
(3) Perform semi-annual, instrumented leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where indirect assessments, i.e. indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient or equivalent are impractical) and an assessment per §192.921 has not been performed.

PHMSA has failed to adequately account for all of these proposed regulatory changes in the PRIA. In Section 3.2 Integrity Management Program (IMP) Process Clarifications\(^\text{62}\), PHMSA states that the changes within §192.935 “clarify preventive and mitigative (P&M) measures based on risk assessments, to include more examples such as correcting root causes of past incidents” and “clarify P&M measures for covered segments for outside force damage.” As mentioned previously in these comments, by inserting the phrase “must include, but are not limited to”, PHMSA has introduced new requirements and in fact is not clarifying the existing requirements, but rather introducing additional and substantial new requirements. The statement within the PRIA that “the proposed changes to the P&M program element requirement would not impose an additional cost burden on pipeline operators” is false and misleading if PHMSA intends to apply these additional requirements. AGA asks that either the regulatory text reflect that these are examples and remedy those examples that do not belong in the list, or adequately account for the new requirements within the regulatory impact assessment for the Final Rule. In Section 3.4 Corrosion Control\(^\text{63}\), PHMSA indicates that the regulatory changes within §192.935(f) & (g) are incorporated into the larger Corrosion Control costs. AGA addresses the inadequacies of these cost estimates in Section V of these comments.

Below are suggested changes to the regulatory language, if PHMSA’s intent was to simply clarify the existing requirements:

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

(a) General requirements. An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Such additional measures Application of these measures for a pipeline must be based on the risk analysis required by §192.917, and must may include actions such as but are not limited to: correction of the root cause of past incidents to prevent reoccurrence; establishing and implementing adequate operations and maintenance processes that could increase safety; establishing and deploying adequate resources for successful execution of preventative and mitigative measures; installing Automatic Shut-off Valves or Remote Control Valves; installing pressure transmitters on both sides of automatic shut-off valves and remote control valves that communicate with the pipeline control center; installing computerized monitoring and leak detection systems; replacing pipe segments with pipe of heavier wall thickness or higher strength; conducting additional right-of-way patrols; conducting hydrostatic tests in areas where material has quality issues or lost records; tests to determine material mechanical and chemical properties for unknown properties that are need to assure integrity or substantive MAOP evaluations including material property tests from removed pipe that is representative of the in-service pipeline; recoating of damaged, poorly performing or disbonded coatings; applying additional depth-of-cover survey at roads, streams and rivers; remediating inadequate depth-of-cover; providing additional training to

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\(^{62}\) PRIA. Page 69

\(^{63}\) PRIA. Page 83.
personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

(b) Third party damage and outside force damage—

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

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

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

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

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

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

(c) Automatic shut-off valves (ASV) or Remote control valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the an ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

(d) Pipelines operating below 30% SMYS. An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.

(1) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and

(2) Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.
(3) Perform semi-annual, instrumented leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where indirect assessments, i.e. indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient or equivalent are impractical) and an assessment per §192.921 has not been performed.

(e) **Plastic transmission pipeline.** An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and (b)(1)(iv) of this section to the covered segments of the pipeline.

(f) **Internal corrosion.** As an operator finds evidence of gains information about internal corrosion on a pipeline, it must enhance its internal corrosion management program, as required under Subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to internal corrosion. At a minimum, as part of this enhancement, operators must consider—

(1) Monitoring for, and mitigating the presence of, deleterious gas stream constituents.

(2) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators and continuous gas quality monitoring equipment at least once per quarter. Use gas quality monitoring equipment that includes, but is not limited to, a moisture analyzer, chromatograph, carbon dioxide sampling, and hydrogen sulfide sampling. (See 192.478 for monitoring frequency)

(2) At least once per quarter, use gas quality monitoring equipment that includes, but is not limited to, a moisture analyzer, chromatograph, carbon dioxide sampling, and hydrogen sulfide sampling.

(3) Use cleaning pigs and sample accumulated liquids and solids, including tests for microbiologically induced corrosion.

(4) Use inhibitors or other mitigative measures when corrosive gas or corrosive liquids are known to be present.

(5) **Address potentially corrosive gas stream constituents as specified in §192.478(a), where the volumes exceed these amounts over a 24-hour interval in the pipeline as follows:**

   (i) Limit carbon dioxide to three percent by volume;

   (ii) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and

   (iii) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas. If the hydrogen sulfide concentration is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points.

(6) Review the program at least semi-annually based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.

(g) **External corrosion.** As an operator finds evidence of gains information about external corrosion on a pipeline, it must enhance its external corrosion management program, as required under Subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to external corrosion. At a minimum, as part of this enhancement, operators must develop a plan to monitor and -

(1) Control electrical interference currents that can adversely affect cathodic protection as follows:

   (i) As frequently as needed (such as when new or uprated high voltage alternating current power lines greater than or equal to 69 kVA or electrical substations are co-located near the pipeline), but not to exceed every seven years., perform the following:

   (A) Conduct an interference survey (at times when voltages are at the highest values for a time period of at least 24-hours) to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected;
(B) Analyze the results of the survey to identify locations where interference currents are greater than or equal to 20 Amps per meter squared; and

(C) Take any remedial action needed within six eighteen months after completing the survey to protect the pipeline segment from deleterious current. Remedial action means the implementation of measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. Any location with interference currents greater than 50 Amps per meter squared must be remediated. If any AC interference between 20 and 50 Amps per meter squared is not remediated, the operator must provide and document an engineering justification.

(2) Confirm the adequacy of external corrosion control through indirect assessment as follows:

(i) Periodically (as frequently as needed but at intervals not to exceed seven years) assess the adequacy of the cathodic protection through an indirect assessment method such as close-interval survey, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG).

(ii) Remediate any damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dBμv for ACVG) under section 4 of NACE RP0502–2008 (incorporated by reference; see § 192.7).

(iii) Integrate the results of the indirect assessment required under paragraph (g)(2)(i) of this section with the results of the most recent integrity assessment required by this subpart and promptly take any needed remedial actions no later than 6 months after assessment finding.

(iv) Perform periodic assessments as follows:
   
   (A) Conduct periodic close interval surveys with current interrupted to confirm voltage drops in association with integrity assessments under sections §§ 192.921 and 192.937 of this subpart.

   (B) Locate pipe-to-soil test stations at half-mile intervals within each covered segment, ensuring at least one station is within each high consequence area, if practicable.

   (C) Integrate the results with those of the baseline and periodic assessments for integrity done under sections §§ 192.921 and 192.937 of this subpart.

(3) Control external corrosion through cathodic protection as follows:

(i) If an annual test station reading indicates cathodic protection below the level of protection required in subpart I of this part, complete assessment and remedial action, as required in § 192.465(f), within 6 months of the failed reading or notify each PHMSA pipeline safety regional office where the pipeline is in service and demonstrate that the integrity of the pipeline is not compromised if the repair takes longer than 6 months. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and

(ii) Remediate insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline in accordance with paragraph (i) above, including use of indirect assessments or direct examination of the coating in areas of low CP readings unless the reason for the failed reading is determined to be a short to an adjacent foreign structure, rectifier connection or power input problem that can be remediated and restoration of adequate cathodic protection can be verified. The operator must confirm restoration of adequate
corrosion control by a close interval survey on both sides of the affected test stations to the adjacent test stations.

2. Use of Direct Assessment for Pipeline Assessments

Under the Proposed Rule, PHMSA has proposed additional regulatory language which would limit the ability to use Direct Assessment (DA) for pipeline assessments, unless all other assessment methods have been determined as unfeasible or impractical. See 81 Fed. Reg. 20843. This is unreasonable as DA is a proven assessment technique that works in addressing the threat of corrosion. (ECDA for external corrosion; ICDA for internal corrosion; and SCC DA for stress corrosion cracking). In addition, DA is a predictive tool that identifies areas where corrosion could occur while other methods can only detect where corrosion has resulted in measurable metal loss.

It should be noted that the Proposed Rule requires operators to address static threats (manufacturing and construction defects) under the §192.917(e)(3). See 81 Fed. Reg. 20842. Therefore, time dependent threats, specifically corrosion; time independent threats, such as third party damage and outside force damage; and human error are the threats that remain for an operator to evaluate through pipeline assessments. By imposing a specific regulatory requirement to address static threats, there is no justification for PHMSA to remove the use of DA as an assessment method for addressing the remaining threats. The capability of DA to identify time dependent threats has been proven.

AGA also believes it is unreasonable for PHMSA to write a regulatory requirement which rejects a valid and proven integrity assessment methodology and codify a preference of other methods. Each pipeline is unique in its operations and its design, construction and maintenance; therefore, the threats applicable to each pipeline are unique and how an operator chooses to assess these threats should also be unique.

PHMSA refers to past incidents and “ongoing research and industry response to the [Advanced Notice of Proposed Rulemaking] ANPRM” to support emphasis on ILI technology and pressure testing. See 81 Fed. Reg. 20817. However, there is no industry study that would suggest DA does not work effectively to identify corrosion defects when identified as an integrity threat and when adhering to a DA technically-based procedure. This includes the pre-assessment step which validates that DA can be applied successfully to a particular pipe segment. Pipes that have dis-bonded coating for instance, or are buried extremely deep are identified as poor candidates for ECDA. An operator who applies Direct Assessment should not be required to justify its use as an exclusive assessment method every time it is applied to address the threat of corrosion. AGA agrees, however, operators should be required to justify decisions made in their implementation in addressing the risk of external corrosion, internal corrosion and stress corrosion cracking. In light of this, PHMSA has not put forth any reasoned justification that would support such a dramatic shift in the way that industry conducts assessments.

AGA maintains that it is not PHMSA’s role as a federal agency to impose its preferences for how operators should choose between proven assessment methods, as it attempts to do under §192.921(a)(6), “Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (d)(5) of this section.” If this language is codified, it would put operators in a position of having to defend its use of DA to assess for corrosion and
demonstrate in every instance how it was determined that the other methods were not practical or desirable to use. As AGA has stated in previous comments submitted to PHMSA, whether or not a pipeline is considered able to accommodate inspection by means of an instrumented in-line inspection tool is largely subjective and not well-defined. If promulgated, this rule would require an operator to continually demonstrate why a pipeline is not able to be inspected by ILI. It is not appropriate for PHMSA to codify how an operator chooses between assessment methods for any threats, as long as methods are effective in identifying pipeline defects attributed to a particular threat.

Free-swimming flow-driven ILI tools are often not compatible with intrastate transmission lines operated by LDCs for a number of reasons. Conditions must exist in order to assess a pipeline by ILI and obtain valid data: (1) constant and adequate flow to move the tool; (2) non-variable pressure conditions that may impact the speed by which the tool moves; (3) a lack of pipeline diameter impediments such acute as bends, valves, etc. (4) a redundancy in the system in the event of an abnormal operating condition; and (5) the ability to insert and remove the tool from the system. AGA offers a definition for *Able to accommodate inspection by means of an instrumented in-line inspect tool* in Section IV.C of these comments. Based on the 2015 Gas Transmission Annual Report, 61% of AGA membership’s intrastate transmission pipelines are unable to accommodate inspection by means of an instrumented in-line inspection tool, which equates to 34,282 miles. In promulgating any standard, PHMSA is obligated to consider the “appropriateness of the standard for the particular type of pipeline transportation or facility.” See 49 U.S.C. §60102(b)(2)(B). PHMSA has not provided justification for applying the same limitations on the use of DA across all transmission pipelines, despite its recognition of the distinctions between intra- and interstate transmission pipelines.

AGA also asserts that the ECDA process is often more effective than ILI in providing operators with a better understanding of critical conditions external to the pipeline, such as cathodic protection (CP) and coating conditions. ECDA helps identify trends in low CP along the entire pipeline which helps operators apply preventative remediation to avoid future external corrosion conditions, whereas ILI gives an understanding of the existing metal loss conditions without reference to the external CP trends or potential for future corrosion along the pipeline. ECDA also is very accurate and cost effective in identifying coating holidays which can help operators identify trends in mechanical damage or other coating degradation issues. Using ILI to determine coating conditions requires the use of an Electromagnetic Acoustic Transducer (EMAT) tool which is significantly more expensive to run than DA tools used in the industry. AGA highly recommends that PHMSA consider the key benefits unique to DA and not limit its use when DA can be applied effectively for applicable threats.

In addition to the above, PHMSA is proposing to incorporate many items into pipeline safety regulations, which govern how DA is to be conducted by an operator. AGA believes many of these items represent opinions of good practices that should be included in a DA plan, rather than provisions that represent minimum safety requirements that presumably could lead to a pipeline failure, if not met. Furthermore, DA is inherently a process that requires the operator to develop its own procedures, founded on corrosion control principles and industry standards, statistical sampling, and incorporating results from pipe examinations to validate the process.

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64 The fact that intrastate pipelines are often not capable of accommodating an ILI tool was expressly acknowledged by PHMSA in the PRIA. PRIA at page 35 (“The relatively high percentage of intrastate pipeline assessed by pressure test and direct assessment in the 2010-2014 time period is attributed to the fact that a larger percentage of intrastate pipelines are unable to accommodate ILI tools (i.e., they are not ‘piggable’)."

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Examples in the Proposed Rule where PHMSA is providing additional requirements and restrictions over the use of DA include the following:

- PHMSA is proposing several additional requirements for the use of ICDA that are redundant with or exceed the NACE SP0206-2006 standard. In §192.927, the regulation should simply incorporate the NACE standard by reference.
- PHMSA is proposing several additional requirements for the use of SCC DA that are redundant with or exceed the NACE SP0204-2008 standard.
- Under proposed §192.710, assessment methods are listed for non-HCA transmission pipelines in Class 3 and 4 locations and transmission pipelines in MCAs that are able to accommodate inspection by means of an instrumented in-line inspection tool. Under §192.710(c)(6), it reads “Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess (due to low operating pressures and flows, lack of inspection technology, and critical delivery areas such as hospital and nursing homes) using the methods specified in paragraphs (d)(1) through (d)(5) of §192.923 and with the applicable requirements specified in §§192.925, 192.927 or 192.929.

AGA suggests the following revisions to the proposed regulatory language pertaining to Direct Assessment:

§192.1109 – What assessment methods can an operator use?
Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess (due to low operating pressures and flows, lack of inspection technology, and critical delivery areas such as hospitals and nursing homes) using the methods specified in paragraphs (d)(1) through (d)(5) of this section. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with the applicable requirements specified in §§192.925, 192.927 or 192.929; or

§192.921 – How is the baseline assessment to be conducted?
(a)(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (d)(5) of this section. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

In Section V of these comments, AGA discusses the impacts that these limiting qualifiers have on the cost impact of this proposed rule.

3. Transmission Integrity Management Program Risk Assessments & Models

PHMSA’s Proposed Revisions for Threat Identification and Integration Are Unnecessarily Prescriptive and are Ultimately Unworkable

PHMSA has proposed the addition of new datasets to be included in Transmission Integrity Management Program (TIMP) Risk Models, and a requirement for spatial analysis of integrity threats. The proposal also includes
four new elements for risk assessments that will require operators to quantify risks versus the historically applied relative risk ranking methodology. Additionally, PHMSA is proposing mandatory validation of datasets included in ASME B31.8S: Managing System Integrity of Gas Pipelines, and integration of datasets not contained within ASME B31.8S. See proposed changes in §192.917.

AGA supports interactive threat analysis and incorporation of the outcomes of the analysis into risk models. However, AGA believes that PHMSA’s proposed requirement to mandate data integration, verification, and validation of an expanded number of datasets would serve to dilute the progress that operators have already undertaken to advance risk assessments. The Proposed Rule would require operators to gather, verify, and validate the integrity of 48 sets and subsets of information, plus “other pertinent information derived from operations and maintenance activities and any additional tests, inspections, survey, patrols, or monitoring required under this Part.” This level of prescriptiveness distracts from safety instead of increasing the safety and reliability of transmission systems. Additionally, the proposed changes do not include an implementation timeline as written, and imply that operators would be required to implement quantitative or probabilistic risk models immediately upon the effective date of the final rule, without regard to the time, challenges, and costs of data collection and integration, not to mention the time necessary to evaluate and implement the requirements in the final rule.

The proposal also assumes that all operators currently have Geographic Information Systems (GIS) and the ability to conduct spatial analysis of integrity threats. Creating and maintaining a GIS is not a regulatory requirement, nor is it expressly proposed to be required by the Proposed Rule. Operators utilize the systems that are most effective for their operations to implement integrity management programs. Requiring a GIS of all operators, as inferred by this code change proposal, and requiring the prescriptive list of data in a geospatial format, is a tremendous and time consuming burden. For operators without a GIS, and operators without the listed data in a geospatial format, it would dilute an operator’s advancements in pipeline safety as they focus their resources to obtaining the data and entering it into a GIS. This would entail a shift in the manner by which operators manage their risk models, from optimizing a methodology that was effective for their pipeline system to a methodology required by the regulation.

AGA reminds PHMSA of the significant investments already made by operators for their risk assessment processes. Operators have historically gathered data and considered all relevant threats for risk assessment programs as required by §192.917 and ASME B31.8S. Currently, operators are required to gather and integrate datasets outlined in Section 4 of ASME B31.8S and to gather and evaluate the datasets referenced in the non-mandatory Appendix A in B31.8S. PHMSA is now proposing to go further and require operators to verify and validate datasets in Section 4 of ASME B31.8S and to add datasets through proposed paragraph §192.917(b)(1). In the detailed comments that follow, AGA is supportive of interactive threat analyses being undertaken by operators. However, AGA highlights why particular datasets included in the proposed §192.917 language will be difficult or impossible to verify and validate, why the implied probabilistic risk model requirement may not result in better risk assessments due to data limitations and other factors, and why this proposal does not advance pipeline safety. Prescriptive requirements for risk models are contrary to the integrity management principle of focusing resources on those areas of highest risk. AGA discourages the copying of requirements from Industry Consensus Standards into regulations without the context of the entire standard, as this can create situations where required activities can be misunderstood or applied inappropriately, leading to regulatory uncertainty.
AGA understands the terms validation and verification of datasets to describe only the comparison of data derived from assessments and O&M activities to the datasets utilized in the operator’s risk model. AGA supports this action if this was PHMSA’s intent. Conversely if it was not PHMSA’s intent for operators to do field verification of existing datasets, this was not accounted for in the PRIA, which is discussed further in these comments. To this end, AGA recommends that PHMSA provide clarity on the meaning of the terms validate and verify.

Operators have been actively researching historical records on the proposed attributes relevant to the associated risk analysis for a transmission pipeline and operators are integrating those attributes if the data improves the quality of the risk analysis. AGA suggests that the only method to gather, verify, or validate data as proposed by this section should be the review of available construction records, which must recognize the limited availability and/or legibility of these records. For example, for pipe coating methods, the general type of coating may be known. However, comprehensive specification knowledge may not be available. To gather information for other proposed data sets such as hardness, toughness, hard spots, and disbonded coating condition would require the use of resource-intense, non-standard in-line inspection technology that currently cannot be deployed on all transmission pipeline segments that would require data gathering. The associated costs resulting from this effort were not included in the PRIA, suggesting that PHMSA did not intend for these tools to be used for gathering these data sets. AGA recommends that PHMSA add additional language consistent with the proposed costs in the PRIA to clarify the extent of effort operators are required to perform to gather these additional data sets. AGA also believes that operators should be responsible for determining which attributes are relevant or applicable to their systems in deciding which data sets to integrate into their risk models. The proposed risk assessment language (§192.917(c)) seems to support this conclusion because it includes a requirement for a sensitivity analysis. If the sensitivity analysis indicates that a factor is not meaningful to characterize the risk of failure, the operator should not have to gather data on that factor. Further, AGA emphasizes that operators should not be required to retroactively obtain data that was not required through prior regulations. This is outside of the scope of PHMSA’s authority.

AGA is concerned that the prescriptive language proposed in this section provides no way for operators to exclude specific data attributes that do not address a known or perceived threat on that pipeline segment. Operators should be allowed to determine which data sets add value to the risk analysis when considering their system specifically. The inclusion and required integration of non-impactful datasets would divert resources away from the evaluation of more impactful datasets. Including non-impactful datasets that would ultimately result in a diluted risk analysis. The gathering and evaluation of the new datasets proposed by PHMSA should be a consideration, rather than a prescriptive requirement. (See AGA’s proposed §192.917(b) in Appendix A of these comments).

Certain data elements for some pipe sections or systems may be known but cannot be verified, or are known but cannot be validated. It may not be feasible to gather additional data or improve the quality of data for certain segments, sections, or systems through additional research or field investigation. It is therefore necessary for a risk modeling approach to accommodate the use of reasoned or inferred estimates that conservatively reflect the values of other similar segments on the pipeline or in the operator’s system. For example, the piping material manufacturing date for a segment or system that went in service in 1959 is not explicitly known and records may no longer be available and cannot reasonably be located. However, the manufacturing date should generally align with the in-service date given material sourcing practices in place during that time period. In the absence of more
definitive information, the *in-service date* can be used as a conservative proxy for the manufacturing date for the purposes of risk modeling.

AGA supports the perspective that operators gather data and conduct risk assessments with accurate and validated data. However, the minimum standards prescribed by regulation should allow the operators to determine the priority of the data gathering efforts as additional information becomes available. Operators bear the onus of which data collection efforts are relevant to support their unique operating conditions and analysis. Operators should also be permitted to have flexibility to prioritize *verification and validation* of data, and to break down the activities for (1) data gathering and (2) *verification and validation*, over a predetermined timeline.

Operators should also be allowed to develop their own timelines for data gathering, verification, and validation for specific datasets, and provide a plan on how they are moving forward. As information is gathered through Material Verification activities in the proposed §192.607, the data will be incorporated into risk models as operators deem it relevant. If an operator can show something that negates the need for information (e.g. threat elimination), then there should not be a need for related data to be gathered moving forward. Timelines for different datasets listed may vary depending on availability, quality, or difficulty in data integration. AGA also suggests allowing operators to follow varying timelines when utilizing data that currently exists, but may not be validated when the risk model is run.

AGA member companies are making every effort to *verify and validate* relevant datasets; however, the scope and feasibility of these new efforts should be left up to each operator for reasons described later in this section of the comments, with the expectation that *verification and validation* of all records for a specific dataset may not be possible. The gathering and evaluation of the new datasets proposed by PHMSA should also be a consideration left to the operator’s judgment, rather than a prescriptive requirement (see AGA’s proposed §192.917(b) in Appendix A of these comments).

Operators should also be allowed to utilize supported, sound engineering assumptions, as is allowed by ASME B31.8S, for datasets until data is verified and validated. AGA proposes that unverified and invalidated data values may be used where necessary, but with reasonable and corresponding evaluation in the resulting risk score. For example, when assigning an index score ranging from 0 to 10 for a particular data value, if a typical value would be 3 and it is not verified, then assign a value of 4. If it is also not validated, then assign a value of 5. Operators should be able to use values that conservatively reflect the values of other similar segments within the pipeline system. As additional data is obtained, these default values will be updated to reflect actual data. It should be noted that operators would not use the unavailability of data as justification for excluding threats, in accordance with Section 4.4 of ASME B31.8S. It is also important to note that not allowing the use of supported, sound engineering values may place a focus on data collection and validation for assets of lesser risk, thus contradicting the goal of optimal risk management and improving pipeline safety. It will also result in excessive increases in costs to operators and the public which are not currently reflected in the PRIA.

AGA notes its concerns that PHMSA’s proposal is based on “the degree of progress operators *should be making, or should have made*, during the first 10 years of the integrity management program.” See 81 Fed. Reg. 20816 (emphasis added). PHMSA’s desire for where operators should be with their integrity management program should not and cannot form the basis for its proposed requirements. PHMSA provided no timeline for
progress associated with the integrity management program. PHMSA cannot now expect or assume that operators have made a specified amount of advancement. A proposed standard based on PHMSA’s unsubstantiated expectations is not reasonable nor appropriate. See 49 U.S.C. §60102(b).

Finally, AGA disagrees with much of PHMSA’s description of its proposed changes as clarification or as codifying industry standards within the regulatory text. See 81 Fed. Reg. 20816-17. As noted in these comments, PHMSA’s proposal would impose additional requirements on operators, and departs from industry standards. Neither of which is consistent with PHMSA’s description. In addition, PHMSA has failed to provide a reasoned justification, description or analysis of these departures and requirements. References to NTSB recommendations that are directed to a single operator in regards to a specific situation do not provide the justification or reasoned determination necessary to support applying these recommendations more broadly through regulations. Nowhere does PHMSA provide the type of reasoned justification necessary to impose each of the prescriptive elements of this proposal or meet the requirement that its regulations be feasible, reasonable, practical, and cost beneficial.

Risk Assessments

Historically, PHMSA has required that operators “must conduct a risk assessment that analyzes the identified threats and potential consequences of an incident for each covered segment,” and that this risk assessment follow the guidance from ASME B31.8S. AGA is concerned that PHMSA is requiring, through the proposed modifications to the regulations, that operators move to a quantitative/probabilistic risk model approach. The added requirement that operators perform “sensitivity analysis of the factors used to characterize both the probability of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity,” forces operators to transition to a quantitative / probabilistic risk model to perform this action. See §192.917(c). AGA strongly opposes this requirement, as this is a significant impact on operators and could ultimately render current relative risk models invalid.

To successfully utilize a quantitative risk model, sufficient data on catastrophic events must exist. A comprehensive data set that includes sufficient data on catastrophic events is not currently available to the industry. These types of models also require additional, highly-skilled staff to manage and execute the models. There will be additional upgrades to mapping systems and other data management systems, as well as third-party expertise required to house and manage the models. As mentioned previously, a mid-size AGA operator recently implemented the ability to conduct probabilistic risk analysis through their GIS and spent over $2.6 million dollars to do so. These types of costs have not been accounted for in PHMSA’s PRIA.

With regard to the frequency of evaluating risk models, according to the answer provided by PHMSA in FAQ-234 [2005], operators are required to re-evaluate risk annually. AGA operators agree and are meeting this requirement. The frequency of conducting risk assessments should be defined by the operator, based on when the operator deems that sufficient information has been gathered and evaluated in order to execute a model that provides meaningful and usable results for its operations.

AGA operators support ensuring the ‘validity of methods used to conduct the risk assessments’. However, AGA believes that ‘producing risk characterizations from...industry experience’ would require utilizing risk assessment methodologies from industry studies that are based on industry-wide pipeline data. Applying non-specific methodologies to an operator’s own system could result in an overly complicated risk characterization.
that may not be precise enough when applied to a specific system. AGA is supportive of operators applying their own risk characterization for validation purposes.

Operators may use other forms of risk assessments when evaluating comprehensive risk (i.e. environmental, financial risks etc.). AGA is recommending expanding risk assessment to allow for these additional risk types to be taken into consideration and to allow operators to ‘prioritize’ additional P&M measures coming from a more holistic risk assessment, rather than force Integrity Management Risk Assessments to solely determine the P&M measures.

Within the new §192.917(c)(1), PHMSA proposes that operators “analyze how a potential failure could affect a high consequence area, including the consequence of a worst-case scenario”. AGA is requesting clarification on the term ‘Worst case scenario’. How many scenarios is PHMSA requiring operators to conduct? Do operators need to conduct a separate scenario for each HCA? Determining every possible but speculative worst-case scenario on a system would be impossible and would lead to nearly an infinite number of scenarios to be evaluated. Additionally, the cost estimates associated with the rule in this regard do not capture these costs. The scope, number, and types of scenarios to be considered should be left up to the operator to determine. AGA recommends removing the language from §192.917(c)(1).

In §192.917(c)(3), PHMSA’s proposed language would require that risk assessments “lead to better understanding of the nature of the threat, the failure mechanisms, the effectiveness of currently deployed risk mitigation activities, and how to prevent, mitigate, or reduce those risks”. AGA acknowledges that it is inevitable that operators will become more knowledgeable of their system risk following a risk assessment; however, AGA fails to see how operators can quantify this increase in understanding.

Additionally, in the proposed §192.917(c)(4), PHMSA has added the requirement that operators “account for, and compensate for, uncertainties in the model and the data used in the risk assessment”. In both existing and proposed sections of the pipeline safety regulations, operators are already responsible to account for tool and instrument tolerances and uncertainties when analyzing data. This new requirement appears to add a layer of compensation for uncertainties, which is duplicative and unnecessary.

Lastly, in §192.917(c)(5), PHMSA’s proposed language would require operators “evaluate the potential risk reduction associated with candidate risk reduction activities such as preventative and mitigative measures and reduced anomaly remediation and assessment intervals.” The language here implies that operators are required to apply speculative ‘What-If’ scenarios to risk assessment processes, which are not particularly meaningful for operators utilizing relative risk models since this becomes computationally difficult and potentially meaningless.

PHMSA has created a multi-stakeholder work group, the Risk Modeling Work Group, with the mission statement of: (1) characterizing the state-of-the-art pipeline risk modeling for gas transmission and liquid pipelines, (2) identifying, and if necessary in specific areas, developing a range of state-of-the-art methods and tools capable of addressing the spectrum of pipeline risk management applications, and (3) providing recommendations to PHMSA regarding the use of these methods tools and data requirements. This mission directly aligns with the changes PHMSA is including in the proposed modification to §192.917(c). AGA strongly
urges PHMSA to await the final recommendations of this work group prior to modifying the Risk Assessment section, and recommends that minimal changes to §192.917(c) be included in this rulemaking. See AGA’s proposed changes to §192.917(c) at the end of this section and in Appendix A of these comments.

Attribute-Specific Comments

Within the series of pipeline attributes and “relevant information” that PHMSA has listed in the requirements for §192.917(b)(1), there are six items that AGA requests be clarified by PHMSA in the Final Rule. Additionally, AGA notes that proposed sections §192.917(1)(i) and §192.917(1)(iii) seem to be redundant. AGA requests that PHMSA consolidate these items into one requirement.

1. Aerial Photography: §192.917(b)(1)(xxxiv)
AGA requests clarification on how aerial photography is to be incorporated into a Risk Ranking methodology. AGA suggests that data from a photo may be used by operators, but requiring an image is unnecessary. Additionally, in the preamble “PHMSA seeks comment on whether a time period for updating aerial photography and patroll information should be established.” See Fed. Reg. 20734. AGA believes that PHMSA should not establish a frequency for updating the aerial photography and should allow operators to establish a frequency based on local conditions and operator knowledge.

2. Hard Spots: §192.917(b)(1)(iii)
Hard spots are not a material property, but a material defect similar to a heat-affected zone (HAZ) at the weld, and are therefore inappropriate to include in the list of material properties.

3. Equipment Properties: §192.917(b)(1)(iv)
AGA requests clarity on PHMSA’s intended meaning of “equipment properties” and what equipment would be deemed relevant in a risk assessment or risk model. AGA believes this attribute is unnecessary and suggests its removal from the final rule.

There are three attributes that AGA believes to be unnecessary, too complicated, or overly burdensome to obtain for PHMSA to prescriptively require operators incorporate into their risk models.

1. Pipe Grade: §192.917(b)(1)(i)
AGA does not see the value in utilizing the grade of pipe for risk assessment purposes. AGA agrees that Specified Minimum Yield Strength (SMYS) is a valuable attribute from a risk perspective. AGA suggests removing Pipe Grade from the proposed language and replacing it with the more meaningful attribute, SMYS.

2. Industry experience for incident, leak and failure history: §192.917(b)(1)(xxxiii)
Operators currently incorporate their own system performance leak and incident data into their risk models; however, operators are concerned about utilizing other operators’ leak or incident data in risk models. Operators believe that this requirement would lead to the results of ‘industry studies’ being applied to other operators and the corresponding use of another operator’s data without permission (or validation) by that operator. This may require operators to utilize resources for efforts not directly related to the applicable threats in their system. This would raise disclosure issues and potentially eliminate any
release of data by an operator due to legal exposure for the accuracy of any results. AGA requests that PHMSA propose how this particular dataset can be quantified by operators who are not the originator of such data, as the data available through PHMSA sources is not sufficient to perform this action. If PHMSA cannot clearly explain how this data set would be utilized, it should be removed from the final rule.

3. Pipe coating method: §192.917(b)(1)(xi)
This dataset should not be retroactively applied since recordkeeping for this information was not required prior to this Proposed Rule. To the extent these would be retroactive, AGA incorporates concerns and objections noted in other sections of these comments on retroactive records requirements.

New & Modified Requirements
PHMSA has also introduced new requirements into existing sections within §192.917. AGA offers the following comments on those new or modified requirements.

- **Time Independent Threats (§192.917(a)(3))**
PHMSA has attempted to add clarifying language to the requirement that operators account for time independent threats in their risk analysis. AGA agrees with these new requirements and would like PHMSA to clarify how the term “consideration” is being defined in this section. AGA also requests clarity on whether operators are expected to conduct a one-time investigation on the risk of seismicity and geology, or if there is an expectation of a frequency requirement for re-investigation.

- **Human Error (§192.917(a)(4))**
PHMSA has provided examples to the requirement that human error be recognized as a threat by adding, “such as operational mishaps and design and construction mistakes.” AGA does not believe that PHMSA intends for this to be a retroactive requirement reviewing past construction design documents and AGA believes this will result in regulatory uncertainty rather than a clarification. Therefore, this requirement should be removed.

- **Data Gathering & Integration (§192.917(b)(2) & (3))**
In §192.917(b)(2), PHMSA introduces new regulatory language that operators “employ measures to adequately correct any bias in SME input.” ASME B31.8S, which is incorporated by reference in the current regulations, recommends in Section 5.4 Developing a Risk Management Approach that operators utilize SME’s in conjunction with risk estimates and to mitigate bias by ‘outlining the impact of assumptions, or the potential risk variability caused by missing or estimated data’. AGA believes that the need for additional bias control measures is duplicative and unnecessary as operators already incorporate the impact of their assumptions in their risk assessments. AGA agrees that operators should have a standard practice of ‘documenting names and information submitted for the life of the pipeline’, which the majority of operators are already doing within their IM program documentation.

Additionally, in §192.917(b)(3), Spatial Relationships, PHMSA has added a requirement that operators, “identify and analyze spatial relationships among anomalous information,” and that “storing or recording the information in a common location, including a GIS, alone, is not sufficient.” AGA agrees that identification of spatial relationships should be conducted when possible, and notes that this is already being conducted by operators. However, PHMSA should clarify why storing data in a GIS system alone is
insufficient, if an operator has a GIS and has this information in its system. Operators are currently pursuing efforts to combine information from multiple databases and data sources, and to identify these interrelationships within a single system, thus providing robust data accuracy and ease of access. Requiring information to be recorded in multiple locations is costly and is counter to operational and administrative efficiency efforts. Additionally, AGA recommends removal of the term ‘analysis’ from (b)(3) as the requirement to analyze every anomalous spatial relationship would mean analysis of a near infinite number of relationships between threats, which will dilute the risk assessment results. It should be again noted that not all operators have a GIS, there is no current requirement for an operator to have a GIS, and the cost to create and maintain a GIS and spatial datasets is not included in the PRIA.

- Plastic Transmission Pipeline (§192.917(d))

Requirements of section §192.917(d) already indicate that an operator must consider threats unique to plastic transmission pipe. Instead of listing the items out specifically in §192.917(d), PHMSA should consider referencing guidance material that identifies threats to plastic transmission pipe, and provides operators with additional clarity and guidance. If PHMSA is unwilling to reference guidance material, AGA requests that PHMSA clarify what is meant by “brittle pipe, circumferential cracking” and how “external loads” differs from “longitudinal or lateral loads” and “point loading”.

AGA proposes removing the additional language in §192.917(e) and referencing an industry standard for threats. In AGA’s proposed regulatory language, AGA recommends PHMSA leave the new proposed language in §192.917(e) and §192.917(d) in place, but add clarifications to the terms mentioned above.

- Actions to address particular threats - Cyclic fatigue (§192.917(e)(2))

In PHMSA’s proposed modifications to §192.917(e)(2), Cyclic Fatigue, PHMSA has added a requirement to perform Fracture Mechanics Modeling on an annual basis. AGA strongly opposes this new requirement and recommends that PHMSA strike this language in the final rule. AGA has provided detailed comments on Fracture Mechanics in Section IV.A.3.a of these comments and suggests that the reference be changed to represent AGA’s recommendation that Fracture Mechanics be incorporated into Subpart O.

- Actions to address particular threats – Manufacturing and Construction defects (§192.917(e)(3))

In its proposed changes to in §192.917(e)(3), Manufacturing and construction defects, PHMSA has significantly revised the required actions to address manufacturing and construction defects. PHMSA’s proposed regulatory language is convoluted and incredibly confusing. This is compounded by the fact that PHMSA has offered no justification of its proposed changes, other than the cursory description that they are in response to NTSB Recommendation P-11-15. After significant review of the proposed changes, AGA believes that PHMSA proposed revisions would require the following actions:

1. An affirmative obligation to analyze a covered segment to determine the risk of failure from manufacturing- and construction-related defects.
2. A requirement that construction- and manufacturing-related defects cannot be considered stable unless the segment has been subjected a hydrostatic pressure test of at least 1.25 MAOP and has
not experienced an in-service incident due to manufacturing or construction defects. If the segment has experienced an in-service incident, aside from an incident reportable under §191.3 which would be addressed through proposed §192.624, the pipeline must be subjected to another hydrostatic pressure test of at least 1.25 MAOP after the incident.

3. If the pipeline segment has (a) experienced a reportable in-service incident under incident under §192.624(a)(1), (b) MAOP increases, or (c) the stresses leading to cyclic fatigue increase. A segment must be prioritized as a high risk segment for assessment/reassessment purposes and is subject to MAOP Verification under proposed §192.624.

AGA does not believe that PHMSA has provided adequate support, justification, or analysis of impacts of shifting from a risk based requirement if a construction- or manufacturing-related defect is identified, to a mandate that operators “analyze the covered segment to determine the risk of failure for manufacturing and construction defects.” An affirmative obligation to evaluate this risk will require additional resources of operators, yet PHMSA has offered no explanation as to why this revision is necessary or why any revision in the current regulations is warranted.

PHMSA also has provided no justification aside from the NTSB recommendation, that a manufacturing- or construction-defect cannot be considered stable absent a hydrostatic pressure test of at least 1.25 times MAOP. This would require a pipeline that has a valid subpart J or equivalent pressure test to perform an additional hydrostatic pressure test. PHMSA has offered no substantive justification for this requirement. Nor has PHMSA estimated the impact or benefits associated with requiring these hydrostatic pressure tests.

As described in Section IV.A.3 of these comments on MAOP Verification, AGA is concerned that the interaction of this section with the proposed MAOP Verification requirements in §192.624 have not been fully considered. AGA urges PHMSA to separate MAOP Verification due to incomplete records or use of the grandfather clause from the stabilization of manufacturing and construction threats. In order to accomplish this important distinction, AGA recommends that PHMSA remove the applicability in §192.624(a)(1) and address this concern through §192.917(e)(3) and §192.1119, which is proposed by AGA in Sections IV.A.3 and IV.D of these comments. This would provide clarity for operators and regulators on the required actions for pipelines that have had a reportable in-service incident due to manufacturing and construction related defects both in the past and in the future. As described in AGA’s comments on the proposed Subpart Q, AGA recommends that PHMSA limit the requirement for historical incidents to only those which there are publicly available records from PHMSA, as operators are under no obligation to maintain records of incidents that would detail the specificity of the incident to determine whether the incident and pipeline is subject to the proposed requirements.

Further adding to the confusion, as proposed, the obligation to perform a hydrostatic pressure test of 1.25 MAOP would apply to in-service incidents generally, as opposed to “reportable” in-service incidents described in proposed §192.624(a)(1). This would require that a much broader set of less severe incidents be subject to a 1.25 times MAOP hydrostatic pressure test than the subset of pipelines that would be the subject of §192.624. In addition, §192.917(e)(3) would require more stringent assessment – the 1.25 times MAOP hydrostatic pressure test – than the flexible assessment method approach provided in §192.624(c) for the more severe incidents. By generally referencing all in-service incidents, instead of reportable
incidents, the prescriptive requirements are severely expanded. AGA, therefore, proposes that PHMSA modify the regulatory text in §192.917(e)(3) to explicitly reference reportable in-service incidents to remain consistent with their proposal in §192.624(a)(1). See Appendix A for these proposed changes.

In PHMSA’s proposal, pipelines located in HCAs without records of a 1.25 times MAOP pressure test are the same pipelines that are subject to the proposed MAOP Verification requirements in §192.624(a)(2) and (3). The way the regulatory text is drafted, although all of the MAOP Verification methods are referenced, an operator would be forced to use hydrostatic pressure testing for those pipelines. Otherwise, because the segment had not been “subjected to a hydrostatic pressure testing satisfying the criteria of subpart J of at least 1.25 times MAOP,” as proposed in §192.917(e)(3), operators would never be able to consider material and construction threats stable for that segment. AGA, therefore, suggests that PHMSA offer two alternatives to the 1.25 times MAOP pressure test, to remain consistent with PHMSA’s position in §192.624 that these methods are equivalent to a pressure test: (1) a pressure reduction of 1.25 times the highest documented operating pressure, or (2) an assessment by an in-line inspection tool qualified to detect defects that would fail a 1.25 times MAOP pressure test. AGA recognizes that current technologies may not be capable of meeting the requirements of the in-line inspection tool option; however, AGA believes this option needs to be codified in regulatory text, as the potential for this solution is imminent and should be recognized in the regulatory text. See Appendix A for these proposed changes.

Finally, PHMSA has offered no support for subjecting pipelines with reportable construction- or manufacturing-related reportable in-service incidents, MAOP increases, or where stresses leading to cyclic fatigue have increased, to the proposed MAOP Verification requirements. Congress was direct and specific on the pipelines that warranted MAOP Verification: (1) Class 3 and 4 locations and Class 1 and 2 HCAs with records that are insufficient to confirm the established MAOP and (2) previously untested transmission pipelines in high consequence areas operating at greater than 30% SMYS. PHMSA has offered no explanation or justification for expanding Congress’ directive to these categories of pipelines. AGA does not think it appropriate for PHMSA to require MAOP Verification within integrity management. MAOP reconfirmation or verification is a one-time event that occurs in response to PHMSA and stakeholders agreeing that some pipelines should be subject to a one-time verification of the previously established MAOP. By explicitly adding these pipelines to the applicability of §192.624, PHMSA has confused the intent of the proposed regulation section. Is the intent to verify MAOP for pipelines with inadequate records, or is it meant to ensure that material and construction defects are stable?

Impact Assessment Review

AGA believes that PHMSA has severely underestimated the resources necessary to meet the new requirements within §192.917.

Section 3.2.2 of the PRIA states that:

“In accordance with §192.917(b) and §192.917(c), these attributes of data gathering and integration, and risk assessment, are already required by reference to ASME B31.8S, Sections 4 and 5, as if they were set out in the rule in full (see §§192.7(a)). Therefore, this requirement would not impose an additional cost burden on pipeline operators”
AGA believes that this conclusion overlooks many of the potential costs associated with the new language requirements proposed in §192.917 (b): *Data gathering and integration* and (c): *Risk Assessment*, especially since the terms *verify* and *validate* have now been added in the requirements. These are new steps that would be required to be taken, and that have not been included in the PRIA.

Several §192.917(b) and §192.917(c) requirements do not appear in ASME B31.8S Sections 4 and 5 and are not accounted for in PHMSA’s PRIA.

1. The 19 new §192.917(b) datasets that require gathering, integration, verification and validation.
2. SME bias control measures
3. Use of outside technical experts.
4. Worst-case scenario analysis of each HCA.
5. Evaluation of potential risk reduction associated with various candidate risk reduction activities.

There are many aspects to gathering, integrating, verifying and validating new data that should be accounted for in PHMSA’s PRIA. There are incremental expenses during routine operations and maintenance activities for new or added fieldwork activities in order to validate existing data and source new data items resulting in additional company personnel and contractor staffing. Additionally, operators are expecting incremental expenses on existing service contracts to modify the nature of work and the data being collected and provided by third parties, since not all data gathering is done in-house.

There are 19 datasets that PHMSA is proposing to be gathered, integrated, verified and validated that are not in ASME B31.8S. An AGA survey of 45 operators revealed that on average, each operator would incur an additional $2.54 million to undertake records research for the new attributes, and an additional $38.7 million, on average, to generate new data through field verification. Some of the larger cost estimates exemplify the challenge in obtaining these data sets. In some cases, operators have reported the cost to replace the pipeline, as any methodology to retroactively obtain this information would be ill-advised in comparison with replacing the pipeline. The results of the survey were utilized to develop an overview of the average cost to verify data either through records research, or additional field verification. The costs are outlined in Table IV.E.3-1 on the following page:

Table IV.E.3-1. Average Costs per Operator to Verify and/or Validate Datasets Not Previously in ASME B31.8S

<table>
<thead>
<tr>
<th>Attributes from the Proposed Rule not previously in ASME B31.8S</th>
<th>AVERAGE COST</th>
<th>AVERAGE COST</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Records Research Only</td>
<td>Field Verification Only</td>
</tr>
<tr>
<td>Grade</td>
<td>$33,034</td>
<td>$1,360,832</td>
</tr>
<tr>
<td>Hardness</td>
<td>$140,510</td>
<td>$1,866,926</td>
</tr>
<tr>
<td>Toughness</td>
<td>$60,540</td>
<td>$1,384,059</td>
</tr>
<tr>
<td>Hard Spots</td>
<td>$109,822</td>
<td>$12,176,875</td>
</tr>
<tr>
<td>Chemical Composition</td>
<td>$530,730</td>
<td>$2,155,878</td>
</tr>
<tr>
<td>Locations of foreign line crossings</td>
<td>$60,588</td>
<td>$315,705</td>
</tr>
<tr>
<td>Nearby high voltage power lines</td>
<td>$93,395</td>
<td>$254,976</td>
</tr>
<tr>
<td>Test leaks or failures</td>
<td>$57,046</td>
<td>$75,000</td>
</tr>
<tr>
<td>Failure causes</td>
<td>$43,924</td>
<td>$67,143</td>
</tr>
<tr>
<td>--------------------------------------------------------------------------------</td>
<td>--------------</td>
<td>--------------</td>
</tr>
<tr>
<td>Inspection Reports - Pipe coating methods</td>
<td>$65,132</td>
<td>$2,309,667</td>
</tr>
<tr>
<td>Class location</td>
<td>$30,988</td>
<td>$329,615</td>
</tr>
<tr>
<td>Failure investigations required by §192.617, and their identified causes and consequences</td>
<td>$60,396</td>
<td>$405,000</td>
</tr>
<tr>
<td>Guided wave ultrasonic testing</td>
<td>$37,294</td>
<td>$142,222</td>
</tr>
<tr>
<td>Close Interval survey (CIS) and electrical survey results</td>
<td>$86,331</td>
<td>$259,464</td>
</tr>
<tr>
<td>AC/DC and foreign structure interference surveys</td>
<td>$95,826</td>
<td>$1,051,324</td>
</tr>
<tr>
<td>Surveys to detect coating damage</td>
<td>$76,172</td>
<td>$561,679</td>
</tr>
<tr>
<td>Disbonded coating surveys</td>
<td>$94,867</td>
<td>$11,973,082</td>
</tr>
<tr>
<td>Stress corrosion cracking (SCC) excavations and findings</td>
<td>$647,999</td>
<td>$882,625</td>
</tr>
<tr>
<td>Selective seam weld corrosion (SSWC) excavations and findings</td>
<td>$62,832</td>
<td>$612,333</td>
</tr>
<tr>
<td>Industry experience for incident, leak and failure history</td>
<td>$75,757</td>
<td>$150,000</td>
</tr>
<tr>
<td>Aerial photography</td>
<td>$82,159</td>
<td>$395,000</td>
</tr>
<tr>
<td><strong>TOTAL COSTS</strong></td>
<td><strong>$2,545,342</strong></td>
<td><strong>$38,729,406</strong></td>
</tr>
</tbody>
</table>

Also, in AGA’s survey of 45 operators:

a. 95% of companies currently use relative risk models
b. 70% of companies would need to purchase new software
c. 92% of companies would require additional resources or contracted expertise to develop probabilistic/quantitative models

One cost that is not adequately accounted for in the impact assessment, as partially noted above, is the costs associated with the creation, enhancement or updating of existing GIS, pipeline databases, field data collection, work management, and risk analysis systems and tools. All of these programs are involved in gathering, storing, or providing the data points specified. In most cases, this would involve a one-time development, upgrade or implementation expense, as well as additional ongoing internal/external maintenance and support expenses going forward.

Several sections of the Proposed Rule imply that all operators have access to system data through a comprehensive GIS. PHMSA should note that not all operators currently have a GIS, nor is it an existing regulatory requirement for operators to have one. Furthermore, not all GIS and associated pipeline databases currently in use, can accommodate the listed database factors, and some may not be able to be enhanced or updated extensively enough to accommodate them. As a result, the purchase and full conversion to a new GIS product would be required which has not been accounted for in the PRIA.

PHMSA should note that some GIS do not inherently integrate and align risk data. Doing so can be a substantial, hands-on, and labor-intensive process. Additionally, not all GIS have the same formats, file structures, operating systems, and seamless information sharing methodologies. Any proposed regulation should be applicable to both operators with, and without GIS, as there is currently no regulatory requirement to have one.

AGA asked operators for an actual, representative cost breakdown to upgrade and implement a PODS/GIS system able to conduct the type of advanced risk analysis that PHMSA is proposing in the new §192.917(c)
language. Note that Table IV.E.3-2 does not account for subject matter expert consultation fees that may be required to supplement operator knowledge or fees associated with commercially owned data sources.

Table IV.E.3-2. Example of the Costs Associated with a PODS & GIS Upgrade

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Software testing and creation</td>
<td>$500,730</td>
</tr>
<tr>
<td>Hardware Purchases</td>
<td>$48,096</td>
</tr>
<tr>
<td>Software Purchases</td>
<td>$559,287</td>
</tr>
<tr>
<td>External Labor</td>
<td>$466,192</td>
</tr>
<tr>
<td>Expenses</td>
<td>$20,671</td>
</tr>
<tr>
<td>Internal Labor</td>
<td>$902,211</td>
</tr>
<tr>
<td>Construction Overhead</td>
<td>$140,408</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$2,637,595</strong></td>
</tr>
</tbody>
</table>

The modifications to §192.917, whether through prescriptive requirements to include numerous pipeline attributes into risk models, or a conscious directive for operators to adopt probabilistic risk models with robust GIS platforms, needs to be appropriately and adequately accounted for in the regulatory impact assessment. Otherwise, PHMSA should revise the regulatory language to reflect the intent of their proposal.

Below is AGA's proposed changes to §192.917

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

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

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

(b) **Data gathering and integration.** To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather, verify, validate, and integrate existing data and information on the entire pipeline that could be relevant to the covered segment, and should consider verifying and validating data to the best extent practicable. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator should consider gathering and evaluating the set of data specified in paragraph (b)(1) of this section and Appendix A to ASME/ANSI
B31.8S. The evaluation must analyze both the covered segment and similar non-covered segments, and must consider:

(1) **Integration** of information about pipeline attributes and other relevant information, including, but not limited to the applicable datasets detailed below. If an operator is missing data or if data deficiencies exist, inferred or conservative and reasonable assumptions shall be used when performing the subsequent risk assessment:

   (i) Pipe diameter, wall thickness, grade, seam type and joint factor;
   (ii) Manufacturer and manufacturing date, including manufacturing data and records;
   (iii) Material properties including, but not limited to, diameter, wall thickness, grade, seam type, yield strength, ultimate tensile strength, hardness, toughness, hard spots, and chemical composition;
   (iv) Equipment properties;
   (v) Year of installation;
   (vi) Bending method;
   (vii) Joining method, including process and inspection results;
   (viii) Depth of cover surveys including stream and river crossings, navigable waterways, and beach approaches;
   (ix) Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;
   (x) Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;
   (xi) Pipe coating methods (both manufactured and field applied) including method or process used to apply girth weld coating, inspection reports, and coating repairs;
   (xii) Soil, backfill;
   (xiii) Construction inspection reports, including but not limited to:
       (A) Girth weld non-destructive examinations;
       (B) Post backfill coating surveys;
       (C) Coating inspection (“jeeping”) reports;
   (xiv) Cathodic protection installed, including but not limited to type and location;
   (xv) Coating type;
   (xvi) Gas quality;
   (xvii) Flow rate;
   (xviii) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);
   (xix) Class location;
   (xx) Leak and failure history including any in-service ruptures or leaks from incident reports, abnormal operations, safety related conditions (both reported and unreported) and failure investigations required by §192.617, and their identified causes and consequences;
   (xxi) Coating condition;
   (xxii) CP system performance;
   (xxiii) Pipe wall temperature;
   (xxiv) Pipe operational and maintenance inspection reports, including but not limited to:
       (A) Data gathered through integrity assessments required under this part, including but not limited to in-line inspections, pressure tests, direct assessment, guided wave ultrasonic testing, or other methods;
(B) Close interval survey (CIS) and electrical survey results;
(C) Cathodic protection (CP) rectifier readings;
(D) CP test point survey readings and locations;
(E) AC/DC and foreign structure interference surveys;
(F) Pipe coating surveys, including surveys to detect coating damage, disbonded coatings, or other conditions that compromise the effectiveness of corrosion protection, including but not limited to direct current voltage gradient or alternating current voltage gradient inspections;
(G) Results of examinations of exposed portions of buried pipelines (e.g., pipe and pipe coating condition, see § §192.459), including the results of any non-destructive examinations of the pipe, seam or girth weld, i.e. bell hole inspections;
(H) Stress corrosion cracking (SCC) excavations and findings;
(I) Selective seam weld corrosion (SSWC) excavations and findings;
(J) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;
(xxv) Outer Diameter/Inner Diameter corrosion monitoring;
(xxvi) Operating pressure history and pressure fluctuations, including analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;
(xxvii) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;
(xxviii) Encroachments and right-of-way activity, including but not limited to, one-call data, pipe exposures resulting from encroachments, and excavation activities due to development or planned development along the pipeline;
(xxix) Repairs;
(xxx) Vandalism;
(xxi) External forces;
(xxii) Audits and reviews;
(xxiii) Industry experience for incident history;
(xxiv) Aerial photography;
(xxv) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area; and
(xxvi) Other pertinent information derived from operations and maintenance activities and any additional tests, inspections, surveys, patrols, or monitoring required under this Part.

(2) Use objective, traceable, verified, and validated information and data as inputs, to the maximum extent practicable. If input is obtained from subject matter experts (SMEs), the operator must employ measures to adequately correct any bias in SME input. Bias control measures may include training of SMEs and use of outside technical experts (independent expert reviews) to assess quality of processes and the judgment of SMEs. Operator must document the names of all any SMEs involved in data verification, validation and information submitted by the SMEs for the life of the pipeline.

(3) Identify and analyze spatial relationships among anomalous information (e.g., corrosion coincident with foreign line crossings; evidence of pipeline damage where overhead imaging shows evidence of encroachment). Storing or recording the information in a common location, including a geographic information system (GIS), alone, is not sufficient; and
(4) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.

(c) Risk assessment. An operator must conduct a risk assessment that analyzes the identified threats and potential consequences of an incident for each covered segment. The risk assessment must include evaluation of the effects of interacting threats, including the potential for interactions of threats and anomalous conditions not previously evaluated. An operator must ensure validity of the methods used to conduct the risk assessment in light of incident, leak, and failure history and other historical information. Validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator’s and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the factors used to characterize both the probability of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to determine additional preventive and mitigative measures needed (§192.935) for each covered segment, and periodically evaluate the integrity of each covered pipeline segment (§ §192.937(b)). The risk assessment must:

(1) Analyze how a potential failure could affect high consequence areas, including the consequences of the entire worst-case incident scenario from initial failure to incident termination;

(2) Analyzing the likelihood of failure due to each individual threat or risk factor, and each unique combination of threats or risk factors that interact or simultaneously contribute to risk at a common location;

(3) Lead to better understanding of the nature of the threat, the failure mechanisms, the effectiveness of currently deployed risk mitigation activities, and how to prevent, mitigate, or reduce those risks;

(4) Account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and

(5) Evaluate the potential risk reduction associated with candidate risk reduction activities such as preventive and mitigative measures and reduced anomaly remediation and assessment intervals.

(d) Plastic transmission pipeline. An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe.

(e) Actions to address particular threats. If an operator identifies any of the following threats, the operator must take the following actions to address the threat such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.

(1) Third party damage. An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §§192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §§192.921, or a reassessment under §§192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment. An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.
(2) Cyclic fatigue. An operator must evaluate whether cyclic fatigue or other loading conditions (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment. Fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis must be conducted should be considered in accordance with §192.624(d) for cracks. Cyclic fatigue analysis must be annually, not to exceed 15 months.

(3) Manufacturing and construction defects. An operator must analyze the covered segment to determine the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment. If an operator identifies the threat of manufacturing and construction defects in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to a hydrostatic pressure testing satisfying the criteria of subpart J of at least 1.25 times MAOP, or has been subjected to a pressure reduction of 1.25 times the highest documented operating pressure, or has been assessed by an in-line inspection tool qualified to detect defects that would fail a pressure test of 1.25 times the highest documented operating pressure, and the segment has not experienced a reportable in-service incident attributed to a manufacturing or construction defect as identified through publicly available records from PHMSA the date of the pressure test. If the manufacturing or construction defects cannot be confirmed as stable, remediation of the threat will be completed in accordance with the schedule provided in §192.624(b). If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment, and must reconfirm or reestablish MAOP in accordance with §§192.624(c).

(i) The segment has experienced a reportable in-service incident as defined in 192.3 due to a manufacturing-related defect, a construction-related defect, or fabrication-related defect described in §§192.624(a)(1) as identified through publicly available records from PHMSA.

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) ERW pipe. If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe, pipe with seam factor less than 1.0 as defined in §§192.113, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including but not limited to pipe body cracking, seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years (including abnormal operation as defined in §§192.605(c)), or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment or a subsequent reassessment. Pipe with cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with §192.922 §192.624(c) and (d).
(5) **Corrosion.** If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §§192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator’s established operating and maintenance procedures under part §192 for testing and repair.

4. Transmission Integrity Management Program: Covered Segments

Given the complexity and significant increase in regulatory requirements introduced through this proposed rule for gas transmission pipelines, AGA would like to take this opportunity to recommend an addition to the definition of **Covered segment.** Operators may determine it necessary to meet the requirements of Subpart O on pipelines that would be subject to the requirements of §192.710 and §192.713, due to proximity to HCAs or the risks associated with that pipeline. AGA believes, for regulatory clarity, that operators should be able to formally deem those pipeline segments as **Covered segments** under transmission pipeline integrity management, thus eliminating possible dual requirements between Subpart O and the proposed requirements. AGA believes this can be easily addressed through a slight addition to the **Covered segment** definition in §192.903 and by acknowledging this choice in AGA’s proposed §192.1103. This change will have no regulatory burden as it is a voluntary action that operators can choose. See below and in Appendix A of these comments for AGA’s proposed definition for **Covered segment.**

§ 192.903 What definitions apply to this subpart?

**Covered segment or covered pipeline segment** means a segment of gas transmission pipeline located in high consequence areas, or a pipeline that the operator chooses to include in Subpart O based on the risk analysis of their system. The terms gas and transmission line are defined in §192.3.

F. Repair Criteria for Pipelines in HCAs and Outside of HCAs

PHMSA is proposing to implement overly prescriptive repair criteria for conditions discovered on pipelines outside of HCAs. The new section mirrors §192.933: **What actions must be taken to address integrity issues,** for pipelines within HCAs. PHMSA is also proposing to include additional criteria within the scheduled repair conditions.

AGA disagrees with PHMSA’s assessment that the Proposed Rule continues to allow operators to “allocate their resources to high consequence areas on a higher priority basis.” The prioritization of HCAs will not always be feasible for operators once the final rule is promulgated, as the quantity of pipeline mileage assessed annually will increase dramatically due to the requirements within the Proposed Rule. Numerous resources will be focused on assessing and remediating pipelines that are outside HCAs, which will impact an operator’s ability to provide the same historic level of attention to HCAs as has been given in the past. The immediate repair conditions are the same regardless of location, therefore the natural prioritization of HCAs over non-HCAs will not be possible under the rule as proposed. Additionally, the sheer number of segments that will be assessed outside of HCAs

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65 81 Fed. Reg. 20815
may require more resources than those segments within HCAs, and therefore the prioritization of HCAs over other areas will not be achievable. AGA believes there needs to be a codified acceptance that priority will always be provided to immediate conditions found on HCAs versus those found on MCAs or non-HCA Class 3 & 4 locations when discovered simultaneously. This prioritization is necessary to ensure that the repair criteria regulations are practicable, reasonable, and appropriate for the categorization of pipeline – HCAs versus outside of HCAs – to be regulated.

To address these prioritization issues, AGA encourages PHMSA to utilize different terminology for “immediate repair conditions” outside HCAs. AGA proposes the term “high priority conditions” for those conditions found during assessments outside of HCAs that require immediate repairs. AGA supports addressing these conditions with a high priority and additionally supports addressing them “immediately upon discovery,” however a difference in terminology is important for prioritization purposes and will enhance clarity in the final regulations. Operators are already adhering to §192.711 for temporary repairs for leaks, imperfections, or damages on pipelines that operate greater than 40% SMYS. The requirements within the proposed section addressing repair criteria outside HCAs will aid in enhancing safety further during reliability assessments outside of HCAs.

Section IV.D of these comments introduce AGA’s proposal for a new Subpart Q: Reliability Assessments Outside of HCAs. Within that Subpart Q, AGA suggests that PHMSA add a new section §192.1113 to cover repair criteria outside of HCAs. AGA will now refer to the proposed §192.713 as §192.1113 in these comments. The new §192.1113 would serve the same purpose for pipelines assessed outside HCAs as §192.933: What actions must be taken to address integrity issues, in HCAs. AGA would also suggest that PHMSA maintain §192.713 in its current form for the permanent field repair of imperfections and damages.

A primary concern for AGA is the treatment of conditions that have been discovered historically, met the code requirements at that time, or may have been scheduled for repair per ASME B31.8S-2004, Fig. 4 “Timing for Scheduled Responses: Time-Dependent Threats, Prescriptive Integrity Management Plan” Table A repair schedule. These conditions may now have time dependent requirements due to their inclusion in the immediate or scheduled repair conditions under the Proposed Rule or may have a more stringent timeline than that of ASME B31.8S-2004 Figure 4. To ensure clarity, AGA recommends the proposed §192.1113(e) be applicable only to those conditions discovered after the effective date of the rule. See AGA’s comments on Subpart Q and Appendix A’s proposed §192.1113 for these suggested edits.

AGA understands PHMSA’s desire to update repair criteria for assessments within HCAs and supports clarity for repair criteria for assessments outside of HCAs. However, there are specific conditions for which AGA believes justification for the repair timeline is lacking. In some cases, industry research supports alternative timelines. In other cases, AGA proposes alternative wording for the repair condition, which AGA believes will aid in clarity. The following detailed comments highlight those repair conditions for which AGA believes there is reasoned justification for modifications within the Final Rule.

(1) A dent that has any indication of metal loss, cracking or a stress riser.

This repair condition has long been a challenge for operators as there is no common understanding or definition for what is considered “metal loss.” In fact, industry research has shown that stress concentration...
“features have some detrimental effect of fatigue life, but that effect appears to be secondary to dent depth”\textsuperscript{66}. AGA believes there needs to be a distinction between metal loss that is due to a stress concentrator such as a scratch, gouge, or groove versus metal loss that is due to corrosion.

API Publication 1156: Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines, concludes that the results from testing “suggests that there was no adverse synergistic effect of the corrosion and the dents.”\textsuperscript{67} In their 2002 paper, Rosenfeld, Pepper and Leewis noted that “corrosion indicated in a rock-induced dent may be evaluated, graded or prioritized in the same manner as metal-loss corrosion features found elsewhere on the pipe.”\textsuperscript{68} Additionally ASME B31.8: Gas Transmission and Distribution Piping Systems recognizes the criticality of gouges, grooves, and notches, but does not place the same emphasis on general corrosion. “Gouges, grooves, and notches have been found to be an important cause of pipeline failures, and all harmful defects of this nature must be prevented, eliminated, or repaired.”\textsuperscript{69}

Therefore, AGA proposes that PHMSA differentiate these two conditions: (1) metal loss due to a scratch, gouge, grooves or a stress riser and (2) metal loss due to corrosion. AGA maintains that the first should be categorized as an immediate repair condition, while the second should be included in the conditions scheduled for repair. See Appendix A §192.933 and §192.1113 for this suggested proposal.

(2) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency or high frequency electric resistance welded or by electric flash welding."

AGA supports the addition of this immediate repair condition, however proposes that the qualifier “high risk” be added to “high frequency electric resistance welded” seams as this technique is still utilized today and does not possess the same risks as those vintages and manufacturers that PHMSA is trying to highlight. In fact, high frequency electric resistance welded pipe is not categorized in the indications requiring immediate response in ASME B31.8S Section 7.2.1: Metal Loss Tools for Internal and External Corrosion. The ASME standard limits the applicable pipe material types to “direct current or low-frequency electric resistance welding or by electric flash welding.”\textsuperscript{70} The modification of this repair criteria would be coupled with the suggested edit to the scheduled repair criteria described below in detailed comment (3). See Appendix A §192.933 or the proposed §192.1113 for AGA’s suggested modification.

(3) Any indication of Significant selective seam weld corrosion

AGA does not support the specific addition of this repair condition into §192.933 or AGA’s proposed §192.1113. AGA believes that PHMSA has addressed this safety concern through the immediate repair condition where the remaining strength calculation shows a predicted failure pressure less than or equal to 1.1 times the MAOP at the location of the anomaly.

AGA therefore, proposes to remove the “significant selective seam weld corrosion” condition. If PHMSA finds it necessary to explicitly define a condition affecting the seam that constitutes an immediate repair

\textsuperscript{66} API 1156. Page 29
\textsuperscript{67} API 1156. Page 37
\textsuperscript{68} ASME. Rosenfeld, Pepper, and Leewis. Basis of the New Criteria in ASME B31.8 for Prioritization and Repair of Mechanical Damage. IPC2002-27122. 2002.
\textsuperscript{69} ASME B31.8 841.2.4
condition, AGA suggests adding the following to the immediate repair conditions, “An indication of metal loss greater than or equal to 20% selectively affecting a detected longitudinal seam other than those seam types listed in §192.933(d)(1)(iv) or §192.1113(e)(1)(iv).” A 20% metal loss threshold is where AGA understands corrosion begins to contribute to the failure pressure of the pipeline. Another condition could be introduced under the scheduled repair conditions for those indications of metal loss that are less than 10% selectively affecting a detected longitudinal seam other than those seam types listed in §192.933(d)(1)(iv) or §192.1113(e)(1)(iv). This proposal goes beyond ASME B31.8S Section 7.2.1 which says, “indications requiring immediate response are those that... include any corroded areas that have a predicated failure pressure level less than 1.1 times MAOP as determined by ASME B31G or equivalent.” See Appendix A of these comments for a revised §192.933 and the proposed §192.1113, which contains these suggested modifications and additions.

Notwithstanding the technical justification for the change to the repair criteria described above, AGA believes there are significant concerns with the wording of this condition. By saying “any indication” PHMSA is leaving room for various interpretations of what constitutes an indication. The wording used throughout 49 C.F.R. Parts 192 and 195 is “an indication.” At a minimum, this term should be applied for consistency. Additionally, PHMSA has not attempted to define “significant selective seam weld corrosion,” nor provide any substantive description or explanation for it, leaving regulatory uncertainty for both operators and regulators. As stated above, if PHMSA determines it has not addressed this safety concern through its requirements for immediate repair conditions, clarity is needed to define what is meant by the undefined term “significant selective seam weld corrosion” and AGA’s recommendation provides that solution.

(4) An area with corrosion with a predicted metal loss greater than 50% of nominal wall.

AGA suggests that this criterion is not necessary in either §192.933 or AGA’s proposed §192.1113, as it is duplicative of the criterion that requires an appropriate remaining strength predicted failure pressure calculation for the Class location where the condition is found. If PHMSA believes this criterion is separate and distinct, AGA requests clarification on whether PHMSA is insisting upon a repair regardless of the AMSE B31G/RSTRENG analysis results because PHMSA’s justification for the proposed criterion fails to provide a sufficient level of detail from which this can be determined.

Additionally, the phrasing of “predicted metal loss” suggests that the condition is found through ILI versus DA and the metal loss is “predicted” to be 50% regardless of the actual field measurements once uncovered. If PHMSA believes this criterion needs to remain, AGA seeks clarification on the point in time when the 50% metal loss is the threshold, such as when it is predicted off ILI data, or if this is the metal loss actually measured in the field. Lastly, the criterion within the proposed §192.1113 simply says “An area of corrosion” whereas §192.933 states “an area of general corrosion.” If PHMSA accepts AGA’s proposal to add a new section §192.1113 to cover repair criteria outside of HCAs but keeps “An area with corrosion with a predicted metal loss greater than 50% of nominal wall” as the criterion, then there should be consistency between the two sections. In addition, if the term “general corrosion” is used, it should be defined.

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

As stated in the discussion of the criteria above, the use of the word “predicted” in this condition description indicates the assumption of discovery through ILI. AGA requests clarification on when during the
discovery process the threshold should be applied, such as when ILI data is received or when field measurements are performed. AGA proposes that the 50% metal loss threshold be based upon physical measurements in the field to account for uncertainties from the ILI tool. Additionally, AGA requests clarity on the terminology, “widespread circumferential corrosion” as this term is not defined in 49 C.F.R. Part 192.

(6) §192.933: A calculation for the remaining strength of the pipe shows a predicted failure pressure rating at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations.

AGA does not support the addition of repair criteria based upon class location as it contradicts ASME B31.8S repair response timelines which are based upon known or perceived effects the condition will have on the strength of the pipeline. AGA supports INGAA’s comments on this section.

(7) A confirmed condition comprising of a crack or crack-like defect other than an immediate condition

Similar to the use of “predicted” the term “indication” suggests that the condition is found through ILI versus DA and the crack-like defect is an “indication” rather than a field confirmed crack-like defect. As the Transverse Flux Inspection (TFI) tools continue to become more readily available for a variety of diameters, operators will have the ability to move towards using this technology to assess for crack-like defects. However, this technology is relatively new and can report a large volume of false positives which need to be validated through excavations. Therefore, PHMSA should clarify the discovery of the condition and “crack-like” defect as called by the ILI tool vendors.

To avoid confusion regarding repair of ILI indications versus actual conditions that require repair, AGA suggests adding the word “confirm” prior to “repair” in §192.1113(e)(1) and (3), as well as similarly addressing this gap §192.93(d)(1) and (2).

Additionally, AGA suggests that PHMSA mirror §192.933(a)(1) and (a)(2) in either §192.713, or AGA’s proposed §192.1113. This will provide regulatory clarity for operators that are unable to respond within the time limits for certain conditions described in this section or operators that need to take long-term pressure reductions on a pipeline. AGA has added this language to §192.713, or AGA’s proposed §192.1113.

Also critical to this section of the Proposed Rule is the references to §192.607 and the requirement for reliable, traceable, verifiable, and complete material records for the performance of remaining strength calculations. AGA maintains that remaining strength calculations for predicted failure pressure determination have been and can be performed using sound engineering assumptions based upon the information known about the physical characteristics of the pipeline. AGA further discusses this position in Section IV.A.2 on Material Verification within these comments. AGA notes of the 137 corrosion incidents reported to PHMSA since 2009, none occurred on pipeline segments where ECDA was performed and a verification dig occurred. This demonstrates that the existing strategy deployed by operators to use supported, sound engineering judgment to perform remaining life calculations is valid and has never resulted in an incident.\footnote{PHMSA Incident Report Data. 2009-2015.} In Appendix A of these comments, in §192.1113, AGA has added language to every reference to §192.607 that allows for engineering judgements to be utilized until the requirements within §192.607 have been met.
AGA also has significant concerns about PHMSA’s lack of acknowledgement of the impact that modifications to the repair conditions within HCAs and the addition of prescriptive repair conditions for assessments outside HCAs will have on pipeline operators. PHMSA goes as far as stating “the only cost to operators of implementing the repair timeliness criteria is the time cost of money for completing some repairs more quickly than an operator might have done prior to this rulemaking.”72 This assumption permeates the entire PRIA and is invalid. In addition, within the benefit portion of the PRIA, it is assumed that all conditions prescribed by PHMSA for repair would ultimately lead to an incident if not addressed according to the newly proposed timeline. This is a fundamentally flawed assumption. PHMSA has offered no justification to support its premise that absent the new timeline, all conditions will fail.73 In some cases, PHMSA is requiring operators to perform repairs at seemingly arbitrary timelines and failing to acknowledge or capture this cost to operators in the PRIA.

Moreover, AGA would like to call PHMSA’s attention to the fact that PHMSA has only accounted for the changes in repair criteria for §192.933 and has neglected to include the costs for the introduction of §192.713. AGA provides a full estimation for this topic area in Section V of these comments that focuses on the PRIA.

In addition to flawed assumptions and misrepresenting the applicable pipelines, PHMSA has inadequately accounted for the repair costs. Table IV.F-1 provides a side by side of PHMSA Best Professional Judgment for the cost to make repairs, next to actual AGA member data. AGA has also provided the cost to excavate these repairs as this cost was not included in PHMSA’s calculations. This is just one example of the incorrect cost impacts PHMSA has utilized in the PRIA. A further discussion of these issues are found in Section V: Preliminary Regulatory Impact Assessment in these comments.

Table IV.F - 1: Comparison between PHMSA Table 3-63. Range of Typical Repair Cost and Actual Industry Data

<table>
<thead>
<tr>
<th>Repair Method</th>
<th>12&quot; Diameter</th>
<th>24&quot; Diameter</th>
<th>36&quot; Diameter</th>
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</thead>
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<tr>
<td></td>
<td>PHMSA BPJ</td>
<td>AGA Data</td>
<td>PHMSA BPJ</td>
</tr>
<tr>
<td></td>
<td>Weighted</td>
<td>Average</td>
<td>Weighted</td>
</tr>
<tr>
<td>Composite Wrap (5’)</td>
<td>$10,380</td>
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<td>$15,570</td>
</tr>
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<td>Sleeve (5’)</td>
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<td>$34,168</td>
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<tr>
<td>Pipe Replacement (5’)</td>
<td>$44,980</td>
<td>$79,031</td>
<td>$67,470</td>
</tr>
<tr>
<td>Composite Wrap (20’)</td>
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<tr>
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</tr>
<tr>
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<tr>
<td>Excavation for 5' Repair</td>
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<td>$21,482</td>
<td>$0</td>
</tr>
<tr>
<td>Excavation for 20' Repair</td>
<td>$0</td>
<td>$43,013</td>
<td>$0</td>
</tr>
</tbody>
</table>

Finally, AGA has significant concerns with PHMSA’s proposed modifications to §192.711(b)(1). Currently, this section requires operators “make repairs on its system as soon as feasible” on pipelines outside of HCAs that are not covered under Integrity Management in Subpart O. PHMSA has vastly changed these requirements by

72 PRIA. Section 3.1.3 Analysis Assumptions. Page 32.
73 PHMSA cannot claim that operators would be performing these repairs and that there would be any benefit from an avoided incident. Under PHMSA’s logic, there would only be an incident if there was no repair. In this situation, PHMSA would need to estimate the cost of the repair as a cost associated with the Proposed Rule.
referencing prescriptive repair criteria within proposed §192.713 for all pipelines outside of HCAs, not just those subject to the proposed §192.710. In essence, PHMSA’s proposed §192.711 requires operators to repair, schedule or monitor conditions on all pipelines with the same timetable. AGA agrees that pipelines subject to §192.710 should meet the repair criteria within §192.713; however, AGA disagrees that pipelines outside of Class 3, Class 4, and MCA locations should meet the full extent of the proposed section. AGA supports pipeline operators addressing high priority conditions described in §192.713(d)(1) immediately upon discovery, but believes all other conditions should be repaired as soon as feasible. Perhaps most concerning is PHMSA’s lack of acknowledgement of this proposed section within the PRIA, and has provided no justification for this new requirement. AGA’s recommendations for changes to the proposed §192.711 are at the end of this section.

AGA’s proposed changes are listed below and can also be found in Appendix A of these comments.

§192.711 Transmission lines: General requirements for repair procedures.

(a) Temporary repairs. Each operator must take immediate temporary measures to protect the public whenever:

1. A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and
2. It is not feasible to make a permanent repair at the time of discovery.

(b) Permanent repairs. An operator must make permanent repairs on its pipeline system according to the following:

1. Non integrity management repairs: Whenever an operator discovers any condition on pipelines covered by §192.710 [Subpart Q] that could adversely affect the safe operation of a pipeline segment not covered under subpart O–Gas Transmission Pipeline Integrity Management, it must correct the condition as prescribed in §192.713 [§192.1113]. If an operator finds a condition that meets the criteria within §192.713(d)(1) [§192.1113 (d)(1)] on pipelines not covered by Subpart O or §192.710 [Subpart Q], operators will repair the condition immediately upon discovery. All other conditions will be repaired as soon as feasible. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator must reduce the operating pressure to a level not exceeding 80% of the operating pressure at the time the condition was discovered and take additional immediate temporary measures in accordance with paragraph (a) to protect persons or property. The operator must make permanent repairs as soon as feasible.

[Move proposed §192.713 to Subpart Q as §192.1113 and maintain existing §192.713]

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

(a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

1. Removed by cutting out and replacing a cylindrical piece of pipe; or
2. Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(b) Operating pressure must be at a safe level during repair operations.

§192.1113 What actions must be taken to address integrity issues outside HCAs?
(a) This section applies to transmission lines. Line segments that are located in high consequence areas, as defined in 192.903, must also comply with applicable actions specified by the integrity management requirements in subpart O.

(b) General. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made so as to prevent damage to persons, property, or the environment. Operating pressure must be at a safe level during repair operations.

(1) Temporary pressure reduction. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the assessment segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, see §192.7); AGA Pipeline Research Council, International, PR-3-805 (R-STRENG) (incorporated by reference, see §192.7) to determine the safe operating pressure that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. Pipe and material properties used in the remaining strength calculation must be documented in traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based in accordance with §192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgments may be used. An operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action. An operator must also notify a State pipeline safety authority when either an assessment segment is located in a State where PHMSA has an interstate agent agreement or an intrastate covered segment is regulated by that State.

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

(c) Repair. Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe; or

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(d) Schedule for evaluation and remediation. An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (e) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.
(e) **Remediation schedule.** For pipelines not located in high consequence areas, an operator must complete the remediation of a condition discovered after [the effective date of the rule] according to the following schedule:

1. **Immediate repair High priority conditions.** An operator must confirm and repair the following conditions immediately upon discovery:
   - (i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in § 192.7(c). Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with §192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgments may be used.
   - (ii) A dent that has any indication of metal loss due to a scratch, a gouge, cracking or a stress riser.
   - (iii) Metal loss greater than 80% of nominal wall regardless of dimensions.
   - (iv) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency or high risk high frequency electric resistance welding or by electric flash welding.
   - (v) Any indication of significant stress corrosion cracking (SCC).
   - (vi) Any indication of significant selective seam weld corrosion (SSWC). An indication of metal loss greater than or equal to 20% of nominal wall selectively affecting a detected longitudinal seam other than those seam types listed in §192.1113(e)(1)(iv).
   - (vii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

2. Until the remediation of a condition specified in paragraph (d)(1) is complete, an operator must reduce the operating pressure of the affected pipeline to the lower of:
   - (i) A level that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, determined using ASME/ANSI B31G (“Manual for Determining the Remaining Strength of Corroded Pipelines” (1991) or AGA Pipeline Research Committee Project PR-3-805 (“A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe” (December 1989)) (“RSTRENG,” incorporated by reference, see § 192.7) for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used. If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in §192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under
evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgments may be used; or

(ii) 80% of pressure at the time of discovery, whichever is lower.

(3) **Two-year conditions.** An operator must confirm and repair the following conditions within two years of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) 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 longitudinal or helical (spiral) seam weld.

(iii) A calculation of the remaining strength of the pipe shows a predicted failure pressure ratio (FPR) at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations. This calculation must adequately account for the uncertainty associated with the accuracy of the tool used to perform the assessment.

(iv) An area of corrosion with a predicted metal loss greater than 50% of nominal wall.

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

(vi) A gouge or groove greater than 12.5% of nominal wall.

(vii) Any indication of crack or crack-like defect other than an immediate condition.

(viii) An indication of metal loss less than 20% of nominal wall selectively affecting a detected longitudinal seam other than those seam types listed in §192.1113(e)(1)(iv).

(ix) A dent that has any indication of metal loss due to corrosion.

(4) **Monitored conditions.** An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) 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).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% 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.

(f) **Other conditions.** Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules and methods defined in the operator's Operating and Maintenance procedures.

(f) **In situ direct examination of crack defects.** Whenever required by this part, operators must perform direct examination of known locations of cracks or crack-like defects using inverse wave field extrapolation (IWEX), phased array, automated ultrasonic testing (AUT), or equivalent technology that has been validated to detect tight cracks (equal to or less than 0.008 inches). In-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards,
including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection and in metallurgy and fracture mechanics for accuracy for the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

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

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

(1) Temporary pressure reduction. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, see §192.7); AGA Pipeline Research Council, International, PR-3-805 (R-STRENG) (incorporated by reference, see §192.7) to determine the safe operating pressure that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. Pipe and material properties used in the remaining strength calculation must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based in accordance with §192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgements may be used. An operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement or an intrastate covered segment is regulated by that State.

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

(b) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator
demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period the operator must notify OPS, in accordance with § 192.949, and provide an expected date when adequate information will become available.

(c) **Schedule for evaluation and remediation.** An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) **Special requirements for scheduling remediation** —

(1) **Immediate repair conditions.** An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions if confirmed:

(i) Calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly for any class location. Suitable remaining strength calculation methods include ASME/ANSI B31G (incorporated by reference, see §192.7), PRCI PR-3-805 (R-STRENG) (incorporated by reference, see §192.7), or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result. Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with §192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound judgements may be used.

(ii) A dent that has any indication of metal loss such as a scratch, a gouge, or stress riser.  
(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.  
(iv) Metal loss greater than 80% of nominal wall regardless of dimensions.  
(v) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency, or high risk high frequency electric resistance welding or by electric flash welding.  
(vi) Any indication of significant stress corrosion cracking (SCC).  
(vii) Any indication of significant selective seam weld corrosion (SSWC). An indication of metal loss greater than or equal to 20% of nominal wall selectively affecting a detected longitudinal seam other than those seam types listed in §192.933(d)(1)(v).

(2) **One-year conditions.** Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of the confirmed discovery of the condition:

(i) A smooth dent located between the 8 o’clock and 4 o’clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).
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 longitudinal seam weld.

A calculation of the remaining strength of the pipe shows a predicted failure pressure ratio at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations.

An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.

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

A gouge or groove greater than 12.5% of nominal wall.

Any indication of crack or crack-like defect other than an immediate condition.

An indication of metal loss less than 20% of nominal wall selectively affecting a detected longitudinal seam other than those seam types listed in §192.933(d)(1)(v).

A dent that has any indication of metal loss due to corrosion.

Monitored conditions. An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and reliability assessments for any change that may require remediation:

(i) 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).

(ii) A dent located between the 8 o’clock and 4 o’clock positions (upper 2/3 of the pipe) with a depth greater than 6% 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.

(iii) A dent with a depth greater than 2% of the pipeline’s diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

G. Spike Test

The industry has had numerous conversations on the benefits and disadvantages of spike tests. In AGA’s September 9, 2013 comments on the Integrity Verification Process, AGA supported the application of spike tests specifically for “those pipelines which have the threat of cyclic fatigue or stress corrosion cracking”. AGA is aware that PHMSA’s emphasis on spike testing comes from the NTSB Recommendation P-11-14, and AGA supports addressing the intent of the NTSB recommendation:

Amend Title 49 Code of Federal Regulations 192.619 to delete the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike.

However, PHMSA is proposing the requirement of a spike test in six different scenarios, which go beyond AGA’s original support:
(1) MAOP Verification, Method 1: Pressure tests: if the pipeline segment includes legacy pipe or was constructed using legacy construction techniques or the pipeline has experienced an incident since its most recent successful subpart J pressure test (§192.624(c)(1)(ii)).

(2) Fracture Mechanics Modeling: to determine the remaining life of the pipeline at its MAOP. (§192.624(d))

(3) Pipeline Assessments outside HCAs: to meet the requirements of the proposed §192.710.

(4) TIMP Assessments: to address the threats, such as “stress corrosion cracking, selective seam weld corrosion, manufacturing and related defects, including defective pipe and pipe seams, and other forms of defect or damage involving cracks or crack-like defects” on pipelines in HCAs per §192.921(a)(3).

(5) Stress Corrosion Cracking Direct Assessment: mitigation of significant SCC through a hydrostatic testing program including spike tests.

(6) TIMP reassessments: appropriate for the threats listed in (4) above in §192.937(c)(3).

The language within §192.506(a), listed below, seems to indicate a broader and more prescriptive application of spike tests, in addition to the six scenarios listed above:

*Each segment of an existing steel pipeline that is operated at a hoop stress level of 30% of specified minimum yield strength or more and has been found to have integrity threats that cannot be addressed by other means such as in-line inspection or direct assessment must be strength tested by a spike hydrostatic pressure test in accordance with this section to substantiate the proposed maximum allowable operating pressure.*

If PHMSA is simply attempting to reiterate the desired application of spike tests, AGA believes this is unnecessary. The only unique element that is introduced through §192.506(a) is the limitation of spike tests to pipelines operating greater than 30% SMYS. AGA agrees with this principle, but believes this can be achieved through direct reference of the applicable code sections that indicate the need for a spike test. AGA suggests the following language for §192.506(a) which is clearer and provides regulatory certainty:

*Each segment of an existing steel pipeline that is operated at a hoop stress level of 30% of specified minimum yield strength or more and is required to be spike tested in §192.624, §192.710 [or §192.1109], §192.921, and §192.937. has been found to have integrity threats that cannot be addressed by other means such as in-line inspection or direct assessment must be strength tested by a spike hydrostatic pressure test in accordance with this section to substantiate the proposed maximum allowable operating pressure.*

AGA reminds PHMSA of the 2004 report by DOT/RSPA that cautions operators on the use of spike testing on low frequency electric resistance welded pipe (LF-ERW) using the formulae outlined in the report:

*“Engineering judgment should be applied before using these formulae when considering a pipeline containing segments of low-frequency electric-resistance welded (LF-ERW) pipe, since testing such*
The report also states that a universal reassessment interval should not be defined due to the degradation of a pipeline’s structural integrity from frequent testing and pressure reversals (defeating the purpose of integrity testing). A paper by Kiefner and Maxey of Kiefner & Associates advocates for spike testing, but also states that ILI is often a better alternative to pressure testing:

*The most important reason why a hydrostatic test may not be the best way to validate the integrity of an existing pipeline is that in-line inspection is often a better alternative. From the standpoint of corrosion-caused metal loss, this is most certainly the case.*

*From the standpoint of other types of defects, the appropriate in-line-inspection technology is evolving rapidly and, in some cases, it has proven to be more effective than hydrostatic testing.*

AGA supports the concept of spike tests and agrees with the pressure requirements within the Proposed Rule “the lesser of 1.50 times MAOP or 105% SMYS”. However, AGA fundamentally disagrees with PHMSA’s required duration for the “spike” of 30 minutes. Industry experts have provided technical reports and presentations referencing a shortened timeframe for the duration of the spike test. The references to a 30-minute spike are based on dated and functionally obsolete research and reports. More recent research and reports recommend a much shorter timeframe for a spike test. For example, in a Kiefner & Associates paper titled “Spike Hydrostatic Test Evaluation,” the authors conclude that “the most important consideration is attaining the highest possible test pressure even if for only a few minutes. This philosophy is apparent in ASME B31.8S, Managing System Integrity of Gas Pipelines, which specifies a 10-minute hold time when testing for SCC. In 2013, John Kiefner and Willard Maxey stated, “The idea is to test at as high a pressure as possible, but to only hold it for a short time (5 minutes is good enough).” A 30-minute period is not substantiated by current research and is not reasoned nor justified; further, it has the potential to cause latent defects that are the exact opposite of PHMSA’s intent.

AGA understands PHMSA’s desire to be conservative and therefore, proposes changing the requirement within §192.506(e) to a 10-minute spike test. AGA’s proposed revision to §192.506(e) is listed below:

*After the test pressure stabilizes at the baseline pressure and within the first two hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.50 times MAOP or 105% SMYS. This spike hydrostatic pressure test must be held for at least 30 minutes.*

Lastly, AGA urges PHMSA to reconsider the specification of a hydrostatic pressure test for spike testing. AGA understands that it was the NTSB’s intent to require a pressure test using water; however, PHMSA has provided no independent technical justification for requiring only hydrostatic pressure tests, instead of pneumatic pressure tests. Pneumatic pressure tests that include a spike are safe to perform at 1.5 MAOP for lower percent SMYS pipelines. It addition, a pneumatic pressure test alleviates the issue of removing water from the line.

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following the test. This is a significant issue for many intrastate transmission pipelines, which typically operate at a lower % SMYS and have multiple valves, turns, offshoots, and other infrastructure challenges that make it almost impossible to completely remove water from the system. If PHMSA intends to maintain the requirement for hydrostatic testing for spike tests, the incremental cost needs to be represented in the PRIA and PHMSA needs to provide a reasoned justification for its inclusion. AGA suggests the remove of §192.506(b) and the deletion of the term “hydrostatic” in the section heading.

Based on the above, AGA’s proposed modifications to §192.506 are as follows:

§ 192.506 Transmission lines: Spike hydrostatic pressure test for existing steel pipe with integrity threats.
(a) Each segment of an existing steel pipeline that is operated at a hoop stress level of 30% of specified minimum yield strength or more and is required to be spike tested in §192.624, §192.710 [or §192.1109], §192.921, §192.937. has been found to have integrity threats that cannot be addressed by other means such as in-line inspection or direct assessment must be strength tested by a spike hydrostatic pressure test in accordance with this section to substantiate the proposed maximum allowable operating pressure.
(b) The spike hydrostatic pressure test must use water as the test medium.
(b) The baseline test pressure without the additional spike test pressure is the test pressure specified in §§ 192.619(a)(2), 192.620(a)(2), or 192.624, whichever applies.
(c) The test must be conducted by maintaining the pressure at or above the baseline test pressure for at least 8 hours as specified in §192.505(e).
(d) After the test pressure stabilizes at the baseline pressure and within the first two hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.50 times MAOP or 105% SMYS. This spike hydrostatic pressure test must be held for at least 10 30 minutes.
(e) If the integrity threat being addressed by the spike test is of a time-dependent nature such as a cracking threat, the operator must establish an appropriate retest interval and conduct periodic retests at that interval using the same spike test pressure. The appropriate retest interval and periodic tests for the time-dependent threat must be determined in accordance with the methodology in §192.624(d).
(f) Alternative Technology or Alternative Technical Evaluation Process - Operators may use alternative technology or an alternative technical evaluation process that provides a sound engineering basis for establishing a spike hydrostatic pressure test or equivalent. If an operator elects to use alternative technology or an alternative technical evaluation process, the operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph §192.624(e) of this section. The operator must submit the alternative technical evaluation to the Associate Administrator of Pipeline Safety with the notification and must obtain a “no objection letter” from the Associate Administrator of Pipeline Safety prior to usage of alternative technology or an alternative technical evaluation process. The notification must include the following details:
(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;
(2) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered;
(3) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;
(4) Assessment techniques and acceptance criteria;
(5) Remediation methods for assessment findings;
(6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;

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H. Definitions of Legacy Pipe & Legacy Construction Techniques

PHMSA Should Eliminate the Use of the Terms “Legacy Pipe” and “Legacy Construction Techniques” Or Revise to Exclude Acceptable Manufacturing and Construction Techniques

PHMSA has proposed to define new terms Legacy construction techniques and Legacy pipe and subject pipelines with these characteristics to more rigorous pressure test requirements for MAOP Verification. See §192.3 (proposed definitions); proposed §192.624(c)(1). AGA recognizes PHMSA’s desire to identify pipelines that may be susceptible to manufacturing- or construction-related defects as a result of now-abandoned materials and techniques and AGA supports this philosophy. As defined in the Proposed Rule, however, AGA is concerned that the definitions would unnecessarily subject pipelines without these concerns to the expanded regulatory requirements. For example, several of the construction techniques listed in the legacy construction definition are currently allowed under Part 192.

AGA is also concerned that the proposal fails to recognize that each system is unique and therefore has a distinct integrity management plan that prioritizes risks. In contradiction of PHMSA’s intent, PHMSA’s prescriptive proposal may create greater risks via the misallocation of resources. The ultimate goal of integrity management is to identify the risks that exist to the safe operation of the pipeline system, prioritize those risks and place resources appropriately to mitigate those risks. The risk of a material or construction defect existing on a system is a risk that each operator should consider in their risk prioritization. The information that an operator has on their system may indicate that the risk of a material or construction defect is low. In these cases, prescriptive requirements that mandate specific actions on a low risk threat result in the misallocation of resources away from higher priority risks. Furthermore, material and construction defects are explicitly addressed in §192.917(e)(3) and AGA suggests their inclusion in AGA’s proposed Subpart Q.

Finally, as currently written, the definitions do not explicitly identify their applicability solely to transmission lines and would also apply to distribution systems without notice, explanation or justification. Expansion of the rule beyond transmission and gathering line systems is outside of the scope of the Proposed Rule. Therefore, AGA does not support the current definition for Legacy pipe and Legacy construction techniques and provides suggestions below on how to either remove the terms from pipeline safety regulations, while still meeting PHMSAs intent, or refine the definitions to meet the collective goal of addressing the risks to pipeline safety from specific materials and construction techniques.

PHMSA Should Eliminate the References to Legacy Pipe and Legacy Construction Techniques within the Proposed MAOP Verification Section and Replace the Definitions with Specific Criteria

PHMSA has proposed to subject certain classes and categories of transmission pipelines to MAOP Verification requirements using specific MAOP Verification methods. See proposed §192.624. If an operator chooses to use the pressure test MAOP Verification method, and the pipeline segment includes Legacy pipe or
was constructed using *Legacy construction techniques*, the operator would need to subject the pipeline segment to a more stringent pressure test known as a “spike pressure test.” See proposed §192.624(c)(1)(ii).

AGA believes that the reference to *Legacy pipe* and *Legacy construction techniques* within the proposed MAOP Verification requirements lacks notice to regulated entities and are overbroad, ambiguous and confusing due to the lack of technical justification. AGA believes this issue can be solved by replacing the references to *Legacy pipe* and *Legacy construction techniques* with three criteria that directly relate to the issues PHMSA is attempting to address:

1. pipe segments with a longitudinal joint factor less than 1.0,
2. pipe manufacturing techniques no longer recognized by industry standards, or
3. pipe segments installed using a construction technique no long recognized as acceptable for construction under Part 192.

These three criteria effectively capture all of the material types and construction techniques that PHMSA has listed in the Proposed Rule. For example, Bessemer steel and wrought iron were both fabricated using butt welding, which is no longer recognized as an effective manufacturing technique per API 5L, meeting criteria (2) above. Similarly, some techniques using Electric Resistance Welding have been excluded from API 5L and ASTM 53, including LF-ERW and direct current welding processes, again meeting the criteria (2). AGA believes that any of the materials or construction techniques not directly addressed by these three criteria should not be subject to the more stringent spike hydrotesting requirements within §192.624.

AGA provides the following proposed changes to 49 C.F.R. §192.624(c)(ii):

(ii) If the pipeline segment includes *legacy pipe* or was constructed using *legacy construction pipe* with a longitudinal joint factor less than 1.0 as defined in §192.113, or was known to be installed using construction techniques no longer recognized as acceptable for new construction under part 192, or the pipeline has experienced an incident, as defined by §191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking, then the operator must perform a spike pressure test in accordance with §192.506. The maximum allowable operating pressure will be equal to the test pressure specified in §192.506(c) divided by the greater of 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or §192.620(a)(2)(ii).

With the addition of these criteria in §192.624, AGA believes that codifying the *Legacy pipe* and *Legacy construction techniques* definitions becomes unnecessary. AGA recognizes that in the version of the Proposed Rule that PHMSA submitted to the White House Office of Management and Budget, the terms *Legacy pipe* and *Legacy construction techniques* played a larger role\(^7\), as did the definition of “modern pipe.” The final version of the Proposed Rule published in the Federal Register limited the use of *Legacy pipe* and *Legacy construction techniques* and eliminated the use of the term “modern pipe.” AGA believes that given the limited usage of these terms, the more appropriate approach is to eliminate these definitions from the final rule. This, in turn, will provide clarity.

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In addition, to the extent that PHMSA seeks to impose “spike pressure tests” on a category of pipelines that PHMSA believes represents a specific threat, it is appropriate to add the specific criteria that clarifies where these tests will apply.

AGA also suggests that PHMSA delete the definition of “modern pipe,” which, although is newly defined in the Proposed Rule, it is not used within the Proposed Rule and therefore the regulated entities lack notice of how or when it will be enforced.

If PHMSA Retains the Definitions of Legacy Pipe and Legacy Construction Techniques, Significant Changes Are Required So That the Terms Do Not Encompass Valid Construction Techniques and Materials

If PHMSA ultimately decides to retain the definitions for Legacy pipe and Legacy construction techniques, several revisions are necessary to reduce regulatory uncertainty and exclude pipes and construction techniques that are still valid or are not susceptible to construction- or manufacturing-related defects.

Legacy Construction Techniques

PHMSA has proposed to define Legacy construction techniques as “usage of any historic, now-abandoned, construction practice to construct or repair pipe segments.” See proposed 49 C.F.R. § 192.3. PHMSA describes these definitions as “based on historical technical issues associated with past pipeline failures.” See 81 FR 20807.

As defined, Legacy construction techniques would encompass any technique that has been abandoned, for whatever reason, be it due to cost or advances in technology. Inclusion of “any” abandoned technique goes well beyond techniques associated with pipeline failures, is overbroad, ambiguous, and may include techniques that have no safety concerns but have been abandoned for other reasons. As such, AGA strongly suggests that PHMSA tailor the definition to encompass only those techniques that are “no longer recognized as acceptable for construction under Part 192”.

The usage of the word “including” without additional qualifiers in the definition for Legacy construction techniques raises significant concern for AGA. It adds both ambiguity and uncertainty to the regulation. This language suggests that the list of construction techniques which is included as part of this definition is not comprehensive and therefore might include construction techniques that are not explicitly stated in the definition and of which regulated entities have no notice. This would leave the definition’s scope open-ended and thus not accurately considered in the regulatory impact analysis. Open-ended definitions create regulatory uncertainty for both operators and pipeline safety regulators. If PHMSA elects not to utilize the criteria that directly relate to the issues PHMSA is attempting to address and PHMSA retains the definition for Legacy construction techniques, AGA encourages PHMSA to remove this qualifier and ensure that this list is accurate and comprehensive.

AGA also has significant concerns with several of the specific construction techniques that PHMSA has included within the definition:

- (1) Wrinkle bends: Wrinkle bends are an acceptable technique under Part 192 for any pipe other than steel pipe to be operated at a pressure that produces a hoop stress of 30% or more of SMYS. See 192.315(a). As proposed, however, all wrinkle bends will be defined as “legacy construction techniques.”
If PHMSA is to include the term “wrinkle bend,” it should be modified so that it does not include wrinkle bends that are permitted under Part 192. Without that revision, the term is overbroad and therefore not reasoned or justified.

- **(2) Miter joints exceeding three degrees**: As drafted, this technique would include miter joints that are currently allowed under §192.233. AGA encourages PHMSA to modify the reference to miter joints to exclude those allowed under §192.233.

- **(3) Dresser Couplings**: PHMSA’s “Mechanical Fitting Failure Report Form” F7100.1-2 acknowledges that mechanical pipe fittings are often incorrectly referred to as “dresser fittings.” AGA understands the term “dresser coupling” to reference a specific manufacturer, Dresser Industries, and not a particular fitting technology. AGA believes that PHMSA’s intent was to refer to obsolete seal-only mechanical fittings without restraining elements to prevent joined pipe from separating. This subset of mechanical fittings, however, is not explicitly identified in the definition of *Legacy construction techniques*. Provided that PHMSA’s intent was to address this subset of mechanical fittings, AGA recommends that the language “seal-only mechanical fittings without restraining devices” replace “dresser couplings.” This would ensure that the term would include fittings of concern made by other manufacturers as well as ensure that other subsets of mechanical fittings that have proven to be effective construction techniques are not included within the definition of *Legacy construction technique*.

- **(4) Non-standard fittings or field fabricated fittings (e.g., orange peeled reducers) with unknown pressure ratings**: AGA does not consider these terms to be synonymous with one another. The term “non-standard” is understood by many operators to mean custom ordered or special ordered. An example of a pipeline component that might fall in this category would be a pipe fitting of a size that is not typically manufactured. In this situation, an operator might make a special request that the manufacturer produce a fitting of that particular size. Whereas, the term “field fabricated fitting” is commonly understood by operators to include manufactured fittings that are modified by the operator at the time of construction to allow for their inclusion into a natural gas pipeline system. Both types of fittings are necessary in certain circumstances. Instead of including these undefined terms that could be interpreted in many different ways, AGA suggests that PHMSA reference fittings that fall outside of the scope of §192.153, Components fabricated by welding.

- **(7) Puddle Welds**: “Puddle welds” are recognized by Pipe Research Council International (PRCI) in version 6 of the PRCI Pipeline Repair Manual, which was co-funded by PHMSA, as an acceptable permanent repair method. As such, AGA encourages PHMSA to remove this item from the legacy construction technique definition.

If PHMSA determines that it is necessary that a definition for *Legacy Construction Technique* be codified, then AGA suggests the definition be revised as shown below:

*Legacy transmission construction techniques* mean usage of any historic, now-abandoned, construction practice to construct or repair transmission pipe segments no longer recognized as acceptable for new construction or repairs under this Part, including any of the following techniques:

1. Wrinkle bends that are not allowable under §192.315;
(2) Miter joints exceeding three degrees that are not allowable under §192.233;

(3) Dresser couplings; Mechanical Fittings without restraining elements

(4) Non-standard fittings or field fabricated fittings (e.g., orange-peeled reducers) with unknown pressure ratings Fittings that do not adhere with §192.153.

(5) Acetylene welds; or

(6) Bell and spigots; or

(7) Puddle welds.

Legacy Pipe

PHMSA has proposed to define “legacy pipe” as steel pipe using specific techniques, regardless of the date of manufacture. PHMSA then identifies specific manufacturing techniques and includes a “catch-all” provision to include pipe with a longitudinal joint factor of less than 1.0 “or with a type of longitudinal joint that is unknown or cannot be determined, including pipe of unknown manufacturing specification.”

AGA has significant concerns that, as proposed, the definition would eliminate an operator’s ability to make an informed judgment regarding a manufacturing technique based on supportable, sound engineering judgments. Instead, the proposed definition, in conjunction with other proposed revisions, would require an operator to prescriptively prove, through reliable, traceable, verifiable, and complete records, that a pipe was not manufactured using one of these techniques. As PHMSA is aware, there is currently no obligation for an operator to maintain records regarding manufacturing technique. Because there was never a requirement to maintain this documentation, many operators would be unable to prove through reliable, traceable, verifiable and complete records that a pipe was not manufactured using one of these techniques. The result would be that an extremely broad set of pipelines would, by default, be included in the category of “legacy pipe” for no other reason than the operators did not maintain a record they were never required to have. This would force operators to be overly conservative in matters of integrity management, resulting in excessive expenditures and unnecessary costs passed along to the public.

PHMSA is expressly prohibited from regulating the design, installation and construction of existing pipelines. This prohibition applies equally to recordkeeping requirements. Therefore, it is not legal or appropriate for PHMSA to mandate that operators have reliable, traceable, verifiable and complete records related to pipeline design, installation and construction through the definition of legacy pipe. Additionally, PHMSA is prohibited from mandating that operators have reliable, traceable, verifiable and complete records related to prior actions where the pipeline safety regulation in effect at the time of installation did not require documentation. See Section III.E of these comments for further discussion of record keeping requirements. Furthermore, it should be noted that PHMSA has proposed a Material Verification program that is meant to address its concern of missing records.

AGA strongly suggests that PHMSA revise the definition of Legacy pipe to allow operators to make informed judgments based on supported, sound information and limit its application to those pipes that operators have reason to believe were manufactured using legacy techniques. To achieve this, AGA suggests that PHMSA eliminate the phrase “regardless of the date of manufacture.”

78 In fact, PHMSA has proposed to add such a requirement to a non-retroactive section, meaning that such requirement would not apply to existing pipelines. ADD CITATION
AGA also suggests that PHMSA limit its catch-all provision to those pipes with a longitudinal joint factor, as defined in §192.113, less than 1.0. This will ultimately include those pipes with unknown joint factor due to the fact that §192.113 requires a default longitudinal joint factor of 0.80 for any pipe with an unknown longitudinal joint factor.

If PHMSA determines that it is necessary that a definition for Legacy Pipe be codified, then AGA suggests the definition be revised as shown below:

Legacy transmission pipe means steel transmission pipe with a longitudinal joint factor, as defined in § 192.113, less than 1.0, or was manufactured by a process no longer accepted by industry standards: using any of the following techniques, regardless of the date of manufacture:

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

PHMSA Has Failed to Justify Its Proposal Regarding Legacy Pipe and Legacy Construction Techniques

PHMSA’s lone reference to support its proposal related to Legacy pipe and Legacy construction techniques states that the terms “are used in proposed §192.624 to identify pipe to which the proposed Material Verification and MAOP Verification requirements would apply. The definitions are based on historical technical issues associated with past pipeline failures.” See 81 Fed. Reg. 20807. Nowhere does PHMSA describe how the techniques were identified, the specific “pipeline failures” that were considered, or the threats that PHMSA is trying to avert. Similarly, PHMSA provides no estimate on the number of miles of pipelines that would be included within the definitions, the estimated number of pipeline miles subject to MAOP Verification under §192.624 that would include legacy pipe or legacy construction techniques and the cost of the spike test, or the benefit of its proposal.

Based on AGA’s comments above, it is clear that a significant number of pipeline miles would be included within the definition of Legacy Pipe and Legacy Construction Techniques. AGA membership estimates 6,039 miles applicable to the requirements of §192.624 meet the definitions of Legacy Pipe and Legacy construction techniques as proposed by PHMSA, and thus would be required to perform a spike test per proposed §192.506. Based on this failure to acknowledge the impact or benefit, it cannot be said that the Proposed Rule represents a reasoned determination that the benefits of the proposed definitions and requirements for Legacy pipe and Legacy construction techniques justify its costs. See 49 U.S.C. §60102(b)(5).

I. Record Requirements
AGA recognizes PHMSA’s desire to consolidate into proposed Appendix A the record retention requirements found throughout the regulatory text of 49 C.F.R. Part 192. However, AGA has significant concerns regarding Appendix A’s functional significance. AGA strongly disagrees with PHMSA’s statement that Appendix A functions to “more clearly articulate” the requirements for records preparation and retention for transmission pipelines. See 81 Fed. Reg. 20820. Appendix A introduces entirely new record keeping obligations by including retention requirements and/or retention times for records that are not required by the regulatory text of 49 C.F.R. Part 192. This burden is not accounted for in the PRIA. In addition, several of the retention requirements found in Appendix A would apply solely to distribution facilities, which is outside of PHMSA’s stated scope of the rulemaking. PHMSA provides no assessment of regulatory cost impact, provides an inadequate justification for the addition of this Appendix, and creates significant regulatory uncertainty through the conflicting requirements of existing code sections and the proposed Appendix A.

AGA finds Appendix A to be a cumbersome and unnecessary addition to 49 C.F.R. Part 192. The existing regulatory text of Part 192 provides clear and distinct record keeping requirements. It is the regulatory text that provides the record keeping obligation. PHMSA cannot circumvent this process by imposing a retention requirement through Appendix A. Any differences between the regulatory text and Appendix A will result in regulatory uncertainty, and will detract from PHMSA’s and operators’ ultimate goals of advancing pipeline safety. Therefore, AGA strongly encourages PHMSA to eliminate Appendix A in its entirety from the final rule. If PHMSA insists on retaining Appendix A, it must be significantly revised and adequately justified to reflect only those records and retention times explicitly required by the existing and proposed regulatory text.

The following provides details on the inconsistencies between the record requirements in the regulatory text of 49 C.F.R. Part 192 and Appendix A, and where PHMSA has included record keeping requirements that pertain to distribution pipelines.

**PHMSA Includes New Record Retention and Retention Time Requirements in Appendix A that are Inconsistent with the Regulatory Text.**

There are numerous instances in proposed Appendix A where the “Summary of Records Requirement” is inconsistent with the regulatory text of Part 192. Several record retention requirements outlined in Appendix A would require the retention of a record where there is no obligation to create or retain the record under Part 192. For example, Appendix A lists a record retention requirement for §192.307 titled “Inspection of materials.” Appendix A summarizes the record requirement as “pipe and component material inspections” and would require that these records be retained for the life of the pipeline. However, neither §192.307 itself nor any other section in Subpart G, General Construction Requirements for Transmission Lines and Mains, contain a provision that mandates the creation or retention of documentation for “pipe and component material inspections.” Instead, §192.307 imposes an inspection requirement: “[e]ach length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.” An operator reading §192.307 would be surprised to learn that this obligation to perform a visual inspection also requires written documentation of the inspection to be retained for the life of the pipeline.
Appendix A has effectively introduced an entirely new record retention requirement for §192.307, yet neither §192.307 nor Appendix A acknowledge this new burden or provide specifics on what the record is to contain. For example, is the record intended to merely document that the inspection occurred? Conversely, is the newly required record intended to document the results of the inspection? PHMSA states that Appendix A “provides specific requirements and records retention period.” See 81 Fed. Reg. 20820. However, the proposed language contained within Appendix A does not provide these specific requirements or even guidance. Neither does the regulatory text since §192.307 is silent on the issue of a record.

Another example would be the purported record retention requirement found in §192.283, “Plastic Pipe: joining procedures.” The “Summary of Records Requirement” in proposed Appendix A states that “records of joining procedures, including results of qualifying procedure tests” must be retained for the life of the pipeline. However, §192.283 imposes no specific record keeping or retention requirement. Instead, §192.283 provides the qualification requirements that a written procedure must be subjected to prior to the written procedure being applied. There is no mention or suggestion of a requirement for an operator to retain “records of joining procedures” or the “results of qualifying procedure tests for the life of the pipeline”, nor is a record retention requirement identified elsewhere within Subpart F. Instead, Appendix A has purported to require an entirely new record and record retention requirement for §192.283. In addition to these examples, Appendix A would ascribe record retention requirements to sections §192.144, §192.150, §192.153, §192.305, §192.307, and §192.619 – despite the fact that the regulatory text imposes no such requirement and there is no acknowledgement of these new burdens in the Proposed Rule or PRIA.

There are also numerous instances in proposed Appendix A where the “Retention Time” provided for in Appendix A is inconsistent with or absent from the regulatory text. For example §192.225 titled “Welding Procedures” states that “each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used”. The retention period found in the regulatory text of §192.225 is different from the retention period provided in PHMSA’s proposed Appendix A, which would require the record be maintained for “the life of the pipeline.” In addition to this example, Appendix A would impose a retention time period for sections §192.227(c), §192.459, §192.467, §192.473, §192.477, §192.478, and §192.478(b)(3) that is inconsistent with the regulatory text and there is no acknowledgement of these new burdens in the Proposed Rule or PRIA.

PHMSA appears to implicitly acknowledge that these new retention requirements and retention times are in fact new standards that need to be incorporated into the regulatory text by PHMSA’s proposed reference to Appendix A and retention times in §192.13(e)(1). If PHMSA truly provided Appendix A merely for clarification or convenience, such a reference in the regulatory text would not be needed. However, PHMSA has failed to adequately support or justify including these new retention requirements and retention times in the regulation and has not accounted for the burden of these new regulations. PHMSA has failed to offer any estimate of the impacts or benefits associated with these new requirements, as is required for PHMSA to act within its general authority. Nor do PHMSA’s conclusory and vague statements that it has determined that additional rules are

79 As addressed in detail in AGA’s comments on MAOP Determination and Verification, the current regulations include no explicit obligation to retain documentation of MAOP Determination. In fact, PHMSA has proposed to include such an explicit requirement through the Proposed Rule. See §192.619(f). This new requirement to document MAOP is missing from Appendix A.
needed to implement the 2011 Pipeline Safety Act, see PRIA at page 95, provide the type of reasoned justification necessary to support PHMSA’s proposed record keeping obligations.

The regulatory text of 49 C.F.R. Part 192 provides specific record keeping requirements. These requirements are clear and distinct, suggesting that where the regulatory text is silent on records, no record is required to be retained unless directed by an operator’s procedures in support of code. Otherwise the explicit record keeping requirements would be superfluous. It is the regulatory text that provides the obligation to retain a record, not Appendix A. PHMSA appears to recognize this distinction, given the note found in the column heading:

Summary of Records Requirement (Note: Referenced code section specifies requirements. This summary provided for convenience only.)

In addition, PHMSA states in the preamble of the Proposed Rule that Appendix A would “more clearly articulate the requirements for records preparation and retention for transmission pipelines.” See 81 Fed. Reg. 20820. Therefore, Appendix A should only identify the very specific record keeping and record keeping retention requirements that are in 49 C.F.R. Part 192.

To the extent that PHMSA is attempting to impose new or revised regulatory requirements through Appendix A, AGA strongly objects to this course of action. PHMSA has not aligned Appendix A with regulatory text nor identified sufficiently any of these new record retention obligations or retention time periods. In addition, PHMSA provides no rationale for what appears to be new record keeping and record keeping retention requirements in Appendix A, nor the cost impacts of these new obligations in the PRIA. In short, PHMSA has not provided the justification, analysis, explanation, or reasoned determination that the benefits justify the costs for each and every one of the new record requirements.

As noted above, there are numerous inconsistencies between Appendix A and the regulatory text, many of which are substantial in nature. Thus, while PHMSA’s attempt to provide a summary chart in Appendix A is laudable, the potential for inconsistencies and confusion to both the operators and regulators outweigh the benefits of introducing this section. Appendix A should be eliminated from any final rule. If kept, Appendix A should only identify the very specific record keeping and record keeping retention requirements that are in 49 C.F.R. Part 192.

PHMSA Includes Items in Appendix A that do not Pertain to Transmission Pipelines.

The title of PHMSA’s proposed Appendix A is “Records Retention Schedule for Transmission Pipelines.” However, Appendix A includes several record retention requirements that apply to distribution pipelines, not transmission pipelines.

For example, although §192.16, Customer Notification, is included in Appendix A, the regulatory text makes it clear that it would only apply to distribution systems:

80 To the extent that PHMSA relies upon Section 23 of the 2011 Pipeline Safety Act, PHMSA reliance is misplaced. As discussed elsewhere in these comments, nothing in Section 23 addresses the obligation to document or retain documentation. Instead, Section 23 required a verification of existing records.
(a) This section applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment.

The language clearly states that §192.16’s area of applicability is customer service lines, i.e., distribution lines, not transmission lines.

Appendix A also includes a record retention requirement for §192.383, Excess Flow Valve Installation. Although there is an obligation to maintain records associated with §192.383, excess flow valves are installed where a distribution service line meets a distribution main and would, therefore, not be applicable to transmission pipelines.

Similarly, Appendix A includes several record retention requirements under Subpart G – General Construction Requirements for Transmission Lines and Mains. Subpart G applies to both distribution and transmission lines. If PHMSA retains Appendix A, the references to Subpart G record requirements should differentiate the requirements listed for Subpart G sections between distribution mains and transmission lines.

It is AGA’s hope that these distribution-related record retention requirements were mistakenly included in Appendix A. However, to the extent that PHMSA is intending to broaden the applicability of these record keeping requirements and apply them to distribution operators, AGA strongly objects.

PHMSA Inappropriately Imposes the “Reliable, Traceable, Verifiable, & Complete” Standard on all Record Keeping Requirements Listed in Appendix A.

PHMSA’s proposed language preceding Appendix A states that all records must be “reliable, traceable, verifiable, and complete” (RTVC), pursuant to proposed §192.13(e). AGA’s significant concerns with PHMSA’s proposed application of RTVC is discussed in detail in Section III.E. AGA reiterates its position that the application of RTVC is inappropriate and fails to recognize the different goals and purposes of different types of records. AGA believes that if any record standard should be codified, it should be a “traceable, verifiable, and complete” standard, and should only apply as it was originally intended, to those records relied upon for determining MAOP. To apply a records standard more broadly creates a significant burden that has not been justified and brings regulatory uncertainty to the existing records.

PHMSA Has Not Considered the Impact of Maintaining Documents for the “Life of Pipeline”

The majority of the records identified in PHMSA’s proposed Appendix A would need to be retained for the “life of pipeline.” AGA has already expressed its concern that, for the most part, these retention times are inconsistent with the applicable regulatory text. However, the “life of pipeline” retention time is in itself problematic.

PHMSA has tied the retention time to the “pipeline” life. As PHMSA is aware, “pipeline” is defined broadly to include “all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.” §192.3. PHMSA has offered no justification for why records specific to a component need to be retained for the life of the “pipeline.” More problematic is the practical application of
retaining these records and linking them to the “pipeline” life. For example, through Appendix A, PHMSA would require records demonstrating welder qualification be retained for the “life of a pipeline” as opposed to the “life of the pipe segment.” Once that “pipe segment” has been replaced, if there are still other aspects of the “pipeline” in service, all of the associated qualification records would still need to be maintained, even for the replaced segment. A component of a pipeline will likely always remain in service, requiring operators to keep records in perpetuity.

In addition, PHMSA has not acknowledged the significant impact of maintaining and organizing these records for the life of a pipeline. Linking a record to a specific component and pipeline, ensuring that such a record can be accessed in the future, as operating and data management systems change, and maintaining the records in perpetuity is an enormous and costly undertaking. The regulatory impact analysis provided by PHMSA does not address any cost or benefit impact to this proposed addition of Appendix A.

Summary
In summary, PHMSA provides no assessment of regulatory cost impact of the new record keeping and retention requirements listed in Appendix A, provides an inadequate justification for the addition of this Appendix, and creates significant regulatory uncertainty through the conflicting requirements of existing code sections and the proposed Appendix A. AGA therefore requests that PHMSA eliminate Appendix A. If PHMSA does include Appendix A in the final rule, in addition to AGA’s other suggestions, PHMSA must at a minimum include an effective date for the proposed requirements. This will create a clear demarcation for the new requirements that will be clearly understood by operators and inspectors and will help to avoid misinterpretations of the effective date of new record keeping requirements.

2. Prospective Materials, Design & Construction Records

PHMSA has proposed new record requirements to document pipeline materials (§192.67), pipe design (§192.127), pipeline components (§192.205), welder qualification for steel pipelines (§192.227), and qualifications for joining plastic pipe (§192.285). AGA would like to point out that by proposing to add these record requirements, PHMSA is expressly acknowledging that the current pipeline safety code does not require an operator to maintain these particular records or any other records not specifically called out in regulations or the operator’s procedures required under the various parts of the code. AGA’s additional comments on these sections follow.

Potential Retroactive Application

As discussed previously in Section III.E of these comments, AGA has significant concerns over PHMSA’s proposed record keeping requirements, including the scope and potential retroactive application of these requirements. The record keeping requirements proposed in §192.67, §192.127, and §192.205 are not included in what operators understand, and what PHMSA has stated, to be “retroactive” subparts of the pipeline safety regulations.\(^{81}\) In addition, AGA is concerned that the phrase “acquire and retain” found in §192.67 and §192.205, and “make and retain” in §192.127 would imply that the obligation to maintain these records is a retroactive requirement. In addition, without a clear effective date within the regulatory text, AGA is concerned that these requirements could be applied retroactively.

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\(^{81}\) AGA’s concerns with the retroactivity of proposed requirements is discussed in more detail in Section III.B.
record keeping requirements would improperly be imposed on pipelines already in existence at the time of the final rule’s publication.

While AGA does not believe it was PHMSA’s intent to require operators to acquire original records documenting the manufacturing standards of pipe materials,82 pipe design, or pipeline components for existing pipelines, AGA is concerned that this regulatory uncertainty could occur based on the use of confusing language in the proposed regulation, such as “acquire and retain” and “make and retain,” and the lack of an effective date for these sections. This could cause the misusage of the new record requirements on assets installed prior to the effective date of this Final Rule. PHMSA should revise the sections listed above to eliminate all possible ambiguity and clarify the intent of the change is for new pipelines installed after the effective date of the final rule. Specifically, PHMSA should eliminate the language that suggests that an operator must retroactively obtain records and should add an effective date to these provisions.

§192.67 Records: Materials

AGA questions the necessity of the numerous records listed in each of the sections referenced above, and in particular proposed §192.67. PHMSA has included an exhaustive list of records necessary to document “yield strength, ultimate tensile strength, and chemical composition of pipe materials.” In addition, although §192.55, Steel pipe, is referenced, this section does not list these individual material properties, but instead provides specifications required of steel pipe. AGA maintains that a Mill Test Report (MTR) is sufficient to provide appropriate documentation of pipe materials. The MTR is a document well understood and recognized in the industry and it contains all information needed by operators to safely operate and maintain their pipeline systems. Furthermore, the MTR contains all information requested by PHMSA. By requiring operators to retain the MTR for new pipelines after the effective date of the final rule, PHMSA will ensure consistency and alleviate any uncertainty as to what, if any, additional records would need to be retained.

AGA also is concerned with PHMSA’s use of the term “original” to describe the required steel manufacturing records, which, as used in this context, is vague and will likely lead to regulatory uncertainty. It is unclear exactly what PHMSA means by the term “original”. This seemingly arbitrary requirement to obtain an “original” record, versus an electronic version or copy, will add significant cost and burden to operators with minimal value to pipeline safety. A copy of the document containing the required information is sufficient.83 In addition, many operators have already transitioned or are transitioning to an electronic record keeping system. It is unclear how the “original” would be stored electronically. For these reasons, AGA suggests deleting the term “original.”

§192.205 Records: Pipeline Components

AGA believes that PHMSA has failed to consider pipe diameter as it pertains to the applicability of proposed §192.205. There are numerous small components less than 2” in diameter used to support the operation of a transmission pipeline. These might include couplings, threaded fittings, short lengths of threaded pipe, and tubing. For example, stainless steel tubing might be used in control or sensing lines at regulator stations.

Footnotes:

82 To the extent these would be retroactive, AGA incorporates concerns and objections noted in other sections of these comments on retroactive records requirements.

83 PHMSA recognizes this in its Advisory Bulletin ADB-2012-06 in which it attempts to define the term “traceable” by indicating that a record “...can be clearly linked to original information about a pipeline segment or facility.” PHMSA makes no mention in this definition that a copy, electronic or paper, is not sufficient.
Another example would be small sections of pipe that might be used to monitor and activate automatic or remotely controlled shut off valves installed in accordance with §192.935. These small components are often purchased in bulk with pressure rating and manufacturing specification only printed on the component. It would be difficult to track each of these small diameter components. AGA proposes that the requirements of §192.205 exclude components less than 2” in diameter. This is consistent with PHMSA’s proposed Material Verification requirements listed in §192.607(d)(4)(ii).

§192.227 Qualification of welders and welding operators; §192.285 Plastic pipe: Qualifying persons to make joints.

PHMSA has proposed revisions to §192.227 and §192.285 that would require operators to retain documentation of individual welding and plastic joining qualifications for each individual performing these functions for the life of the pipeline. As PHMSA is aware, welder qualification and joining qualification are continuous processes. As drafted, the regulations do not specify whether an operator is to retain a welder’s original qualification, or the most recent re-qualification before making the weld. Given that a welder or joiner could be qualified for decades, with many re-qualifications occurring over that time period, PHMSA should consider the purpose in retaining these records and require operators to retain only those records necessary for achieving those purposes. It should be noted that the burden of this requirement is not included in the PRIA.

PHMSA’s Authority and Consideration of Impacts

PHMSA states that its authority to impose these new record keeping requirements is derived from Section 23 of the 2011 Pipeline Safety Act. Specifically, PHMSA states that “Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines.” See 81 Fed. Reg. 20808; see also, 81 Fed. Reg. 20809. However, Section 23 only obligated operators to verify their existing records of specific classes of transmission pipelines for purposes of ensuring the records accurately reflected the physical and operational characteristics and confirmed the established MAOP. See 49 U.S.C. §60139(a). The record requirements that PHMSA has proposed would apply to a broader class of pipelines than specified in Section 23(a). Section 23(a) applied to the verification of existing records for existing pipelines. Nothing in Section 23 supports the proposed new record requirements on new pipelines.

PHMSA’s authority to promulgate such record keeping requirements is subject to PHMSA’s consideration of the reasonably identifiable or estimated costs and benefits, and the determination that the benefits justify the costs. See 49 U.S.C. §60102(b)(2), (3), (5). PHMSA has failed to consider these costs and benefits, or make such a reasoned determination in relation to the proposed record keeping requirements identified above. In fact, nowhere in the PRIA does PHMSA acknowledge or address these new requirements. Of similar concern is that PHMSA’s description of these proposed requirements in the preamble to the Proposed Rule, which is a mere description of the regulatory requirement and a conclusory statement that such a requirement is necessary for implementation of Section 23. Aside from the fact that Section 23 does not provide PHMSA the authority to promulgate these standards, PHMSA has offered no explanation or justification on how the proposed standard would effectuate the implementation of Section 23 or how this proposed requirement with improve pipeline safety.

Potential Application to Distribution Systems

The proposed record keeping requirements in §192.67, §192.127, and §192.205 would apply to “operators of transmission pipelines.” AGA assumes PHMSA is intending to impose these new regulations only to
transmission pipelines. However, the regulation should make clear that the “transmission pipeline” is the subject of the regulation, not the “operator of the transmission pipelines.” As currently drafted, the requirements could apply to distribution pipelines operated by “operators of transmission pipelines.” As PHMSA has stated repeatedly it was not its intent to regulate distribution, nor has PHMSA considered the impact of these record keeping requirements on distribution systems, AGA encourages PHMSA to revise these record keeping requirements to apply to the transmission pipeline.

AGA’s encourages PHMSA to make the following revisions to §192.67, §192.127, §192.205, §192.227 and §192.285 consistent with AGA’s comments:

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

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

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

§192.227 Qualification of welders and welding operators.
(a) Except as provided in paragraph (b) of this section, each welder or welding operator must be qualified in accordance with section 6, section 12, or Appendix A of API Std 1104 (incorporated by reference, see §192.7), or section IX of ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, see §192.7). However, a welder or welding operator qualified under an earlier edition than the edition listed in §192.7 may weld but may not re-qualify under that earlier edition.

(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.
(c) Records for transmission pipelines installed after [insert effective date of rule] demonstrating each individual welder qualification at the time of pipeline installation in accordance with this section must be retained for the life of the pipeline.


(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:
   (1) Appropriate training or experience in the use of the procedure; and
   (2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be:
   (1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and
   (2) In the case of a heat fusion, solvent cement, or adhesive joint:
      (i) Tested under any one of the test methods listed under §192.283(a) applicable to the type of joint and material being tested;
      (ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or
      (iii) Cut into at least 3 longitudinal straps, each of which is:
         (A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and
         (B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under §192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator’s system is qualified in accordance with this section.

(e) For transmission pipelines installed after [insert effective date of rule], records demonstrating plastic pipe joining qualifications at the time of pipeline installation in accordance with this section must be retained for the life of the pipeline.

J. Management of Change

AGA supports the concept of Management of Change (MoC) and its application in transmission integrity management and control room centers. AGA also supports operators voluntarily adopting the American Petroleum Institute’s Recommended Practice 1173: Pipeline Safety Management Systems (API RP 1173; PSMS), which includes MoC elements. However, AGA does not support PHMSA’s application of MoC to all pipelines and processes, which occurs with PHMSA’s proposal to move MoC requirements from Subpart O-Gas Transmission Integrity Management to Subpart A-General, §192.13(d). See 81 Fed. Reg. 20735. This move creates a new requirement for each transmission operator to have a formal MoC process to document and evaluate all changes to pipelines and processes, including basic routine maintenance.
PHMSA has significantly underestimated the impact and burden of its proposal, which would dramatically expand the scope of the types of changes to be included as well as the pipelines to which it would apply. Under the existing code, MoC as outlined in ASME/ANSI B31.8S, Section 11, is required to be included in an operator’s integrity management program, applicable only to transmission pipelines in HCAs. PHMSA’s proposal would expand the requirement to develop and maintain an MoC process to all transmission operators, would prescriptively list the elements of an MoC program within the code as opposed to referring to ASME/ANSI B31.8S, and would expand the list of the types of changes to be required to be addressed. PHMSA’s proposal would have a significant impact on all transmission operators, including those operators that have a formal process within their integrity management programs for pipelines within HCAs.

PHMSA’s proposal also represents a departure from PHMSA’s encouragement that operators voluntarily adopt a pipeline safety management system (PSMS), and PHMSA’s repeated statements that PSMS would not be placed into regulation, with the understanding that industry would work towards voluntary implementation of PSMS. AGA and other trade associations have actively been encouraging and promoting the voluntary adoption of PSMS. In early 2015, while PSMS was still in development, AGA created a PSMS discussion group that included nearly 100 company representatives. This discussion group has held frequent calls to discuss PSMS and share how companies are working towards voluntary implementation. Once PSMS was finalized, AGA began a pilot program that includes a dozen pipeline companies that have agreed to voluntarily implement all, or portions, of PSMS. In March 2016, AGA held a workshop to share some of the initial lessons learned from the pilot and invited PHMSA and state pipeline safety representatives to join the workshop. In April 2016, AGA highlighted the PSMS at its annual Operations Conference, which included over 1,100 participants. AGA is currently drafting a PSMS roadmap to assist operators in implementing PSMS. And AGA has already committed to holding another PSMS workshop in 2017. AGA, its members, and other industry sectors are following through on our commitment and we are disappointed that PHMSA is not doing the same.

PHMSA’s Proposal to Codify Management of Change for All Transmission Operators is Inconsistent with How the Industry and PHMSA are Already Addressing Management of Change

MoC is a concept rooted in industry consensus standards. Under the current regulations, operators of transmission pipelines are to include an MoC process within their integrity management programs consistent with the MoC process described in ASME/ANSI B31.8S. In addition, last year the American Petroleum Institute published API RP 1173: Pipeline Safety Management Systems, which is a collaborative effort among industry, PHMSA, the National Transportation Safety Board, states, and the public. MoC is an element of PSMS, which is intended to enhance the effectiveness of risk management and enable continual improvement of pipeline safety performance.

PHMSA’s proposal to codify the MoC process and prescriptively dictate the program requirements is unnecessary at this time and a departure from the collaborative approach this industry has taken on MoC and PSMS. In addition to listing the four topics of change that operators understand to be part of an MoC process – technical, physical, procedural, and organizational changes – PHMSA proposes to add design, environmental, operational, and maintenance changes. The four new change types are not found in any standard or

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recommended practice. The addition represents a shift from the standard found in ASME/ANSI B31.8S, with no explanation or justification either in the preamble to the Proposed Rule or the PRIA. See 81 Fed. Reg. 20735. To implement this proposal, every natural gas transmission pipeline operator would be required to change their current processes, some of which are considered best in class. Adding four new change types will require those operators that already have MoC processes in place, even those which are highly advanced, to significantly revise their processes. Even more importantly, the MoC proposal is so broad that every decision and every change by every individual involved in some aspect of a pipeline’s design through retirement would be required to document that change and how that decision was made.

PHMSA states that the action of outlining an MoC process directly in code will improve visibility and importance of MoC program elements. See 81 Fed. Reg. 20816. AGA respectfully disagrees. Prescribing program elements directly in code does not increase visibility, but suggests that PHMSA intends to override consensus industry standards and recommended practices by unilaterally imposing its view of what elements should be included in an MoC process. Industry standards and recommended practices have always been a collaborative event among multiple stakeholders, including industry, the public, PHMSA, state regulators, and subject matter experts. Placing program elements directly in the regulatory code inhibits innovation and future collaborative solutions to advance the industry.

As an example of how collaborative efforts have worked to find solutions to improve pipeline safety, PSMS was developed through a consensus standard. PSMS was developed in response to NTSB recommendation to API to develop a document that would assist pipeline operators in developing and implementing a PSMS. As noted above, multiple stakeholders assisted in creating PSMS during a multi-year process. Subsequently, in October of 2015, the NTSB accepted this document, noting that it exceeded their original recommendation. The NTSB not only endorsed the document itself, but also commended the efforts of industry organizations such as AGA in promoting and facilitating the adoption of PSMS by its member companies. This collaboration is just one example of how the natural gas industry has voluntarily focused a significant amount of resources for the purpose of minimizing risks and increasing safety.

As noted above, progress is being made as operators voluntarily implement PSMS. Currently, twelve AGA volunteer member companies are piloting the implementation of PSMS. This pilot program is a necessary step in implementing a system-wide PSMS and MoC program. Pilot companies are discovering the challenges and the benefits of the recommended practice and they are sharing this information with other AGA member companies.

Activity on PSMS and system-wide MoC is not limited to the volunteer companies. Additional industry workshops and discussion groups include a significant amount of industry operators. Attendees participate in these industry forums expecting to identify implementation strategies of PSMS and MoC that they can apply to their own unique set of operations.

Industry-wide MoC is already naturally progressing as PSMS becomes an integrated element of the industry. The Proposed Rule would disrupt and complicate operators’ integration of PSMS. It is therefore AGA’s position that the methodical incorporation of PSMS into a company’s safety culture is a better solution than adding a small, modified subset of this recommended practice in the form of the MoC regulation presented by PHMSA in the Proposed Rule.
If PHMSA Does Not Eliminate the Codification of MoC, Significant Revisions Are Warranted

If PHMSA determines it is necessary to codify the concept of MoC for all transmission operators, AGA has significant concerns with (1) the absence of an implementation period, (2) the vague and overbroad scope of its proposal, (3) the lack of a reasoned impact assessment resulting in a serious underestimate of costs and burdens as demonstrated below, and (4) the failure to provide an adequate and reasoned justification for the modifications from current industry standards.

PHMSA Failed to Provide a Reasonable Implementation Period for MoC

As proposed, the MoC process would be retroactive and would have no implementation period. PHMSA’s failure to consider the implementation time demonstrates PHMSA’s misunderstanding of the magnitude and scope of a true MoC process. It is completely unreasonable to believe that any organization can create an MoC process in a short timeframe. Implementing an effective MoC is a learned process. As demonstrated through the AGA companies in the PSMS pilot program, applying an MoC process system-wide requires careful consideration of the operational, organizational, and technological capabilities of a company. PHMSA itself should also understand the process necessary to implement PSMS, including MoC, since adopting the implementation of a safety management system within PHMSA is a part of PHMSA 2021.85

PHMSA’s expectation that an operator could create an MoC process or update an MoC process to include the 4 new change types immediately, as soon as the new MoC requirement becomes codified in the final rule, is obviously unreasonable. PHMSA significantly underestimates the number of changes taking place on a transmission system on an ongoing basis, the level of effort and resources required to develop and implement an effective MoC process, and the time required to change the organizational culture to effectively implement an MoC process. In addition, the significant regulatory changes that PHMSA has proposed in the Proposed Rule will need to be incorporated into any existing MoC process. The effectiveness of utilizing a system-wide MoC process has not been explained or justified, and the hasty implementation of an expanded process would further cloud any actual or perceived benefits of the MoC process.

The Scope of PHMSA’s MoC Proposal is Both Vague and Overbroad

Proposed §192.13(d), states: “Each operator of an onshore gas transmission pipeline must develop and follow a management of change process”. As proposed, this requirement would require an operator of transmission pipelines that also has distribution or gathering pipelines to include those systems in the MoC process. The full scope of the Proposed Rule (since it would include distribution and gathering pipelines operated by transmission operators) is not considered, and would be exorbitantly more burdensome and costly than PHMSA estimates.

Furthermore, PHMSA has proposed to require that each transmission operator “evaluate and mitigate, as necessary, risks to the public and environment....” Proposed §192.13(d). PHMSA has provided no explanation or guidance on what additional actions this proposed requirement would impose in addition to current regulatory requirements. Furthermore, in incorporating the MoC process into the regulatory text, PHMSA adds four new

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85 Written Statement of Administrator Marie Therese Dominguez before the House Committee on Transportation and Infrastructure on Pipeline Reauthorization, Feb. 25, 2016
http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=28a86dd842e13510VgnVCM100000d2c97898RCRD&vgnextchannel=485b143389d8c010VgnVCM1000008049a8c0RCRD&vgnextfmt=print.
change types, but provides no guidance or explanation as to why these change types are necessary or how to implement them.

PHMSA has Seriously Underestimated the Burden and Cost of its MoC Proposal

The analysis PHMSA offers to support its proposal is based on faulty assumptions. First, PHMSA costs are premised on PHMSA’s assumption that of the 350 operators that do not have IM programs only 70 operators would need to develop processes to more formally implement the new MoC rule requirements. See PRIA at page 80. PHMSA’s assumptions are not supported and are inaccurate. There is no evidence to suggest that 280 transmission operators that do not have an IM program would have a MoC process already. In addition, there is no evidence to support the PRIA statement that “Pipeline operators currently apply MoC principles to all of their pipeline systems with varying degrees of process formality. Thus, the incremental impact to operators is limited in scope.” See PRIA, page 79. AGA believes that very few transmission operators currently have a MoC in place to the extent proposed, which means that most (if not all) transmission operators would either need to establish a new process or would need to revise existing procedures. Currently, 49 C.F.R. Part 192 only requires MoC for transmission pipelines in HCAs and control centers. PHMSA has failed to account for the costs for an operator with an IM program to expand its MoC process to cover all transmission pipelines and revise it to match the changes as listed by PHMSA in the Proposed Rule. AGA conducted an informal survey of its members to determine the impact of the Proposed Rule on the industry. From the survey, 32 of 38 respondents indicated that they would be required to take various actions to update their current MoC or would need to create a new MoC process consistent with the Proposed Rule.

PHMSA assumes that a “typical pipeline system has 8 compressor stations and 3 piping sections” and that a typical pipeline system would have one compressor station change event and three piping section change events per year. See PRIA at page 79. These assumptions lead to PHMSA’s estimate that that a company would only have 4 MoC events annually. Responses to AGA’s survey ranged from 1 to 450 events annually, with the average being 60 events per year. This average is 1400% higher than PHMSA’s estimate. Even utilizing PHMSA’s estimate that only 4 MoC events would occur annually, the estimate does not take into account the other changes a PHMSA’s proposal would trigger in addition to the physical changes. Proposed §192.13(d) (Technical, Design, Physical, Environmental, Procedural, Operational, Maintenance, and Organizational) and the PRIA cost analysis does not account for these.

PHMSA estimated in the PRIA document (Table 3-68) that it would cost $3,492 per MoC event. The accuracy of $3,492 is questioned, due to responses AGA received to its survey. The median cost of MoC change was reported as $7,695, more than double the estimate in the PRIA. In addition, as noted above, there was gross underestimation of the number of MoCs one gas company could have per year.

PHMSA’s cost analysis estimates that it would only cost a company $2,277 - $9,902 to implement an MoC process. AGA’s survey results suggest that these estimates are also extremely low. AGA members provided a low range estimate of $4,300, which is within the estimate provided in the PRIA. However, AGA members provided high estimates that ranged from $10,400 to $37,138,000, dramatically higher than the $9,902 limit given in the PRIA.

The scope of the implementation of the proposed change to the MoC process will require the development of a software user interface and a database for MoC tracking. In a survey of operating companies...
with formal MoC processes, 85% of respondents reported the expanded MoC requirement will require the use of an electronic system for managing MoCs. This will be necessary to properly organize and track the progress of multiple changes occurring simultaneously. Notably absent from the estimate on table 3-67 of the PRIA is the development of a software application and database for managing and documenting the change process.

The cost to develop a process, procedures, and an electronic tracking system is not insignificant. And the management and implementation of this type of system is also not adequately considered in the impact assessment. The distributed nature of the natural gas business with multiple changes occurring in multiple operating areas simultaneously requires the use of a central electronic system, which impacted individuals can access from any operating area office. In addition, an electronic system is needed to efficiently manage MoC submissions, reviews, and approvals by multiple people in multiple areas. The development and implementation of this type of application is costly, time consuming, and resource intensive; a cost of which is not adequately captured in the PRIA. Using actual operator data, AGA estimates the initial cost of an electronic program will range from $20,000 to $12,000,000. This will be costly for those companies that do not currently have an electronic system, but may now need one with the expansions to this rule.

If the proposed regulations become effective, operators will need to revise existing plans, procedures, and work practices mentioned above to include these new MoC requirements or to create new plans, procedures and work practices to meet these new MoC requirements. In addition to the effort for reviewing and revising these plans, procedures and work practices, employee training, both engineering and operating, would need to be enhanced to cover these new requirements. As written, routine work activities would need to meet MoC requirements, the MoC documentation and approval processes prior to these routine work activities will become overly cumbersome and would cause delays in the routine work activities being performed.

**PHMSA Fails to Provide Adequate Justification for its Proposal**

PHMSA has provided no justification for its decision to expand the MoC process to transmission pipelines system wide, or for its decision to add change types that differ from the previously incorporated industry standard. Instead, PHMSA’s statements on its proposed change are merely an abbreviated description of what the revised regulatory text would require, and would suggest that there have been no deviations from the industry standard. See 81 Fed. Reg. 20808, 16.

The lack of justification PHMSA has provided for the burden to implement MoC may be rooted in a misunderstanding about the scope of a true MoC program. Gas operators have existing operations and maintenance procedures and plans that cover routine operations and work activities such as equipment calibration, seasonal pressure adjustments, above ground piping maintenance such as painting, and pipeline patrol monitoring which includes replacing missing or downed pipeline markers. These activities are already covered in other sections of pipeline safety regulations, such as Subpart M and Subpart L §192.605, and would therefore be redundant to document and retain these records in an MoC process. The proposed regulations regarding MoC requirements would also affect Control Room Management MoC procedures for what is currently considered routine operations such as adjusting pressures, flows and gas volumes depending on weather, supplier issues, or planned construction activities.

AGA questions the addition of the following four new types of changes: design, environmental, operational, and maintenance. The Proposed Rule refers to ASME B31.8S Section 11 as reference. The types of
changes included in the ASME B31.8S Management of Change Section 11 are technical, material, procedural, and organizational. PSMS, outlines an MoC process with four similar categories: technology, equipment, procedural, and organizational. Both ASME B31.8S and PSMS are accepted within the industry. Noting that these two references are similar but do not exactly match on change types, AGA is suggesting that PHMSA remove its listed change types from the final rule. An operator should have the flexibility to designate what change types will be included and how they will be included in their MoC process.

Furthermore, AGA believes the four additional categories could be encompassed in both the original ASME B31.8S and PSMS categories previously mentioned, and could be addressed without adding them as separate categories and forcing companies to significantly revise their MoC processes. The twelve PSMS pilot companies are using the PSMS change types as the basis for their voluntary implementation and any variance would derail significant progress on the adoption and advancement of PSMS and MoC programs. Design is included in the Technical category. Environmental and Maintenance are included in Physical. Operational is a subset of Procedural. The four new change types could be referenced under the current change types where each operator can continue the current structure of developed MoC programs. Because current structures of developed MoC do not typically track a change type under the newly proposed designations, every operator would be forced to change the record keeping of their MoC program. This change in record keeping burden has been underestimated by PHMSA. In sum, the addition of four new change types is unnecessary, burdensome, and fails to enhance pipeline safety or an MoC program.

PHMSA’s justification for giving greater emphasis by placing MoC components directly in the text of code is mistaken. By eliminating the reference to ASME B31.8S Management of Change Section 11, PHMSA is eliminating the reference to detailed guidance on implementing MoC, including gas pipeline specific examples and the requirement to document communication made to any affected parties to ensure the safety of the system.

As stated previously, AGA opposes moving the MoC process from Subpart O, Gas Transmission Integrity Management, to Subpart A, General. AGA members support the continued codification of MoC in §192.911(k) as long as the requirement only references industry standards and does not outline each component of an MoC process. Outlining each component directly in code inhibits the potential for enhancements and future progress. AGA believes improvements to standards should lie directly with organizations that specialize in industry collaboration, such as ASME and API. In addition, outlining each attribute directly in code will now require PHMSA to provide definitions for each attribute.

AGA suggests amending the proposed code to:

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

§192.911: What are the elements of an integrity management program?

AGA’s Proposed Definitions of Change Types

If PHMSA determines, through reasoned justification and taking into account the burden that will be imposed, that referencing the change types in the code is necessary, and that expanding the change types is supported, then AGA members believe it is important to define terms and limits for all types of changes. During the development of these comments, a survey was sent to a sample group of AGA’s members asking for input on definitions of each of the eight listed change types. The definitions listed below combine all responses, creating one definition for each type of change. Although AGA members believe there is not a need for additional change types or a need to call out change types in the Proposed Rule, the proposal requires clarity for all stakeholders. The original four change types accommodate changes to components, equipment, repairs, procedures, and changes in working conditions.

If the MoC provision is retained in the code, AGA suggests amending the proposed code to include the following definitions:

- **Technical change**
  - A significant change to technical data that affects the gas transmission pipeline integrity. Such changes as GIS or other computer program changes or complete software application changes.
  - *This is a current change type outlined in ASME B31.8S.*

- **Design change**
  - A significant change to company specific design methods that could potentially affect gas transmission pipeline integrity.
  - *This is a new designated term that will require operators to change current MoC tracking mechanisms. Design changes are currently covered by Physical changes. Design is part of the Analysis of Implications that is part of the current program and is done with every MoC project.*

- **Physical change**
  - A significant change to a pipeline system and/or operation that could potentially affect gas transmission pipeline integrity (major, minor, temporary, or permanent). Such changes include physical construction or changes in operating pressure, when the intended purpose of the change is different from the existing system.
  - *This is a current change type outlined in ASME B31.8S and it already considers Design, Operational and Maintenance changes.*

- **Environmental**
  - Significant changes related to how the operating environment is being modified due to transmission pipeline integrity.
This is a new designated term that will require operators to change current MoC tracking mechanisms. Environmental is currently considered in the Analysis of Implications that is part of the current. Adding it as a stand-alone change type will only add unnecessary complexity.

- **Procedural**
  - A change to documented procedures or plans that could potentially affect gas transmission pipeline integrity (major, minor, temporary, or permanent). Such changes include regulatory changes, changes to transmission integrity documents or integrity assessment plans.
    - This is a current change type outlined in ASME B31.8S

- **Operational**
  - Significant changes to procedures that affect gas transmission pipeline integrity. This would apply to both temporary and permanent procedural changes.
    - This is a new designated term that will require operators to change current MoC tracking mechanisms. This change type is already considered during a procedural change. When operational changes occur outside of a physical change they are covered by existing standards.

- **Maintenance**
  - If a significant change is made to a transmission line covered under a Subpart M: Maintenance task, an MoC will document the change.
    - This is a new designated term that will require operators to change current MoC tracking mechanisms. This type of change is already covered in the Physical Change type during the Analysis of Implications that is part of the current program.

- **Organizational**
  - A significant change in company organization that affects gas transmission pipeline integrity.
    - This is a current change type outlined in ASME B31.8S

**K. Corrosion**

**1. 49 C.F.R. Part 192 Subpart I - Requirements for Corrosion Control**

PHMSA is proposing to modify Part 192 Subpart I – Requirements for Corrosion. PHMSA explains it believes that certain pipeline safety regulations can be modified to better address corrosion issues. AGA agrees that existing requirements have been influential in protecting pipelines from corrosion damage, such as requirements for electrical surveys (i.e., close interval surveys), interference current (testing), and requirements for internal corrosion control. While PHMSA’s proposals were made with the intent of improving pipeline integrity, and AGA is supportive of that goal, AGA does not support some of the proposed changes that are unnecessarily burdensome, costly to operators as presented, and do not contribute effectively to pipeline safety.

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86 81 Fed. Reg. at 20829.
In §192.461 (External corrosion control: Protective coating), PHMSA is proposing to require operators to conduct direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG) surveys on replaced or repaired onshore transmission pipelines “promptly, but no later than three months after backfill”. Further requirements call for operators to “remediate any coating damage classified as moderate or severe (voltage drop greater than 35% for DCVG or 50 dBμv for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six months of the assessment”. Similarly, in §192.319, PHMSA is requiring operators to conduct DCVG or ACVG surveys on newly installed onshore transmission pipelines promptly after it has been backfilled, “but not later than three months after placing the pipeline in service”.

It should be noted that coating surveys are not always feasible. Excessive depth of cover and excessive pavement can make indirect surveys impossible. While conducting coating holiday surveys post-construction can be considered a best practice, activities that are not always feasible to complete should not be codified within the regulations. Accordingly, AGA requests that this be removed from the final rule. If PHMSA is unwilling to strike this provision from the final rule, AGA has additional comments surrounding the details of the proposed language.

AGA believes that PHMSA should not limit tools for performing coating surveys to only two types. Coating survey tools other than DCVG and ACVG are allowed by NACE SP0502-2010 and thus used as part of the ECDA integrity assessment process for HCAs. Improvement in in-line inspection tool technology will soon allow for the assessment of coating conditions using ILI tools. If other coating surveys are allowed to be performed over HCAs, then an operator should also be allowed to use these survey methods under proposed §192.319(d) and proposed §192.461(f).

AGA strongly believes that three months to conduct coating surveys after backfilling may not provide sufficient time for operators for several reasons. Coating surveys cannot be performed during frozen ground conditions. A mandatory 3-month window does not allow enough time for the ground to thaw during winter weather conditions. AGA is also concerned that three months may not allow sufficient time for the backfill to settle and return to native moisture levels to allow for a successful coating survey to be performed safely and accurately. Furthermore, many operators do not perform these surveys in house; instead they rely on contracted service providers. Operators must be allowed adequate time to schedule coating surveys by qualified personnel. Finally, the three-month requirement is inconsistent with §192.455(a)(2), which allows operators up to 1 year to install cathodic protection. Allowing up to 1 year for coating surveys after backfill would be a logical proposal given the issues and inconsistencies listed above. See AGA’s proposed edits to §192.319 and §192.461 in Appendix A of these comments.

In the PRIA, PHMSA makes the assumption that crews already mobilized to perform main installations, replacements, or repairs are also qualified to perform post-backfill coating surveys. This approach is deemed “significantly less expensive”\textsuperscript{88} in comparison to having qualified survey personnel return at a later date to perform the surveys. However, this assumption is incorrect as most operators utilize outside resources for these tasks as their construction crews do not always hold the necessary qualifications to perform these surveys. Additionally, there is an inconsistency between PHMSA’s proposed regulatory language in §192.461(f), which requires a survey if the repair or replacement results in 1,000 feet or more of backfill length. However, Table 3-71

\textsuperscript{88} Preliminary Regulatory Impact Assessment page 86.
in the PRIA assumes an excavation of 200 feet. This is just one such example of the inconsistencies between the Proposed Rule and the PRIA. This inconsistency is further discussed in Section V: PRIA of these comments.

In §192.465(d) (External corrosion control: Monitoring), AGA would first like to highlight that the proposed changes, as written, will effect both transmission and distribution pipelines. If this was not PHMSA’s intention, this should be clarified in the final rule. Additionally, in paragraph (d), PHMSA is proposing that remedial actions be completed by the next monitoring cycle or within 1 year, whichever is less. AGA supports operators addressing deficiencies in a prompt timeframe and have understood that one year was the interpretation provided by PHMSA for all cathodic protection deficiencies. PHMSA’s proposed language, as written, is too onerous and in some cases infeasible. For example, if an impressed current system with a defective ground bed supporting an impressed current cathodic protection system is discovered during the bi-monthly inspection (§192.465(b)); the Proposed Rule would require the operator to repair or replace the ground bed within 2-1/2 months (next monitoring interval for an impressed current system). In most cases, it will be impossible to replace a ground bed within this timeframe. Extenuating circumstances may include, but are not limited to: land / easement acquisition for a new ground bed, new power pole needed (new location), permits, and winter weather conditions and frozen ground. These same circumstances can also hamper operators’ efforts to remediate within one year. These situations are recognized by the Gas Piping Technology Committee (GPTC) guidance for §192.465, which state in instances where remedial action cannot be completed prior to the next scheduled monitoring cycle, the operator should document the actions taken to correct the deficiency and the expected timeframe for completion. This guidance recognizes that not all cathodic protection deficiencies are the same, and in some situations, they require additional time to correct. At the end of this section, AGA provides recommended changes to the proposed language to require operators to take prompt remedial action to correct deficiencies found through inspection and testing, and takes into account issues such as the ones identified above.

In §192.465(f) (External corrosion control: Monitoring), PHMSA is proposing that close interval surveys (CIS) must be conducted in both directions from the test station with a low cathodic protection (CP) reading at approximately five foot intervals. These proposed requirements will lead to unnecessary and costly work as there are various situations that produce a low CP reading that do not require CIS for identification of the root cause. Electrical shorts to adjacent foreign structures, damaged or inadequate rectifier connections, cable break issues, and power input problems are several instances that can result in low CP readings. It is AGA’s position that these conditions would not warrant the need to conduct a CIS. With proper troubleshooting, these cases can be identified and remediated quickly, thus avoiding spending unnecessary resources on CIS. Operators should troubleshoot, rule out, and/or mitigate the non-systemic causes before possibly conducting a CIS. See AGA’s proposed edits to §192.465 at the end of this section and in Appendix A of these comments.

In §192.473(c) (External corrosion control: Interference currents), PHMSA is proposing to require that interference current testing be conducted on pipeline systems to “detect the presence and level of any electrical stray current” and that they “must be taken on a periodic basis including, when there are current flow increases over pipeline segment grounding design, from any co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures”. This prescriptive proposal requires operators to obtain information relative to load capacities from electric transmission providers. This poses a problem for operators as it may not be possible to obtain this information from outside parties. There are also no requirements for electric companies to share this information nor required timelines to do so, which means that it would be up
to the electric company, not the natural gas company, to provide this information. AGA strongly suggests striking this new requirement as the data being requested is outside of the pipeline operators’ control, making this requirement unachievable. Tasks that are not achievable, and are too prescriptive, do not belong in the regulations. See AGA’s proposed edits to §192.473 at the end of this section and in Appendix A of these comments.

In §192.478 (Internal corrosion control: Onshore transmission monitoring and mitigation), PHMSA has proposed additional requirements to monitor gas stream quality to identify if and when corrosive gas is being transported and to mitigate deleterious gas stream constituents. AGA recommends a more refined and gradual approach to target specific pipelines that may be delivering corrosive constituents. As proposed by PHMSA, operators would be required to invest in significant installations, monitoring, and other gas control equipment. Operators should be allowed to conduct appropriate analyses specific to their systems to determine the appropriate monitoring necessary to ensure pipeline integrity. Additionally, §192.478(b)(3) and §192.478(d) appear to be duplicative in nature. AGA suggests striking §192.478(d) to remove any regulatory uncertainty that may result in this redundancy. See AGA’s proposed edits to §192.478 at the end of this section and in Appendix A of these comments.

In the PRIA, PHMSA claims that the added cost of monitoring corrosive gas (carbon dioxide, sulfur, water, etc.) is “relatively inexpensive”. PHMSA estimates the cost to purchase and install the minimum amount of monitors for the entire industry to achieve compliance (40 or 41 if using the actual total in fifth column of Table 3-75) for all HCA locations is $400,000⁸⁹. AGA firmly states that this is a gross underestimation of regulatory impact as PHMSA does not take into account that local distribution companies have a dependent working relationship with transmission operators to meet tariff requirements. Therefore, PHMSA’s cost estimates are very low for equipment to monitor gas quality for internal corrosion purposes. AGA members estimate the proposed requirements would necessitate installation of at least 437 new gas quality monitoring devices to cost as much as $66,000,000. Also, PHMSA’s PRIA only accounts for the cost of monitoring equipment. The PRIA is silent regarding calibration, inspection, maintenance and other associated ongoing costs for this equipment. Furthermore, the PRIA does not address the ongoing costs for the monitoring program, beyond the equipment costs (operations and maintenance costs, labor costs, laboratory costs, etc.). These are significant costs and must be accounted for in the PRIA.

PHMSA’s substantial underestimation in the PRIA does not accurately account for the impact of the proposed changes to §192.478 as there are significantly more “points where gas with potentially corrosive contaminants enters the pipeline” than the assumed 40 or 41 locations. If PHMSA is attempting to limit the applicability of this requirement to only those locations where large interstate transmission pipeline operators receive gas from natural gas producers, then the language within §192.478(b)(1) needs to be modified to reflect this intent. The regulatory uncertainty that results from language, such as “potentially corrosive”, results in operators performing actions for the sake of regulatory compliance instead of truly addressing pipeline safety threats and the intent of the rule. AGA proposes that PHMSA’s intent can be realized through a modification to the proposed §192.478. See Appendix A and below for the proposed changes to §192.478.

Lastly, in §192.485 (Remedial measures: Transmission lines), PHMSA has added prescriptive requirements for determining the strength of pipe based on actual remaining wall thickness in the event that general corrosion

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⁸⁹ PRIA Table 3-75 Estimation of Costs for Internal Corrosion Monitoring
is found. While AGA supports this change in its entirety for gas transmission pipelines, AGA believes the final two sentences within §192.485(c) that reference Material Verification should not be applicable to gas gathering lines, as aforementioned in the gathering line comments in Section IV.M. To allow for the exception of this requirement, which is consistent with PHMSA’s statements during webinars on the Proposed Rule, AGA suggests breaking §192.485(c) into two sections. See AGA’s proposed edits to §192.485 at the end of this section and in Appendix A of these comments.

AGA’s proposed modifications to the sections discussed above within Subpart I are provided below and in Appendix A of AGA’s comments:

§192.319 Installation of pipe in a ditch.

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that:
   (1) Provides firm support under the pipe; and
   (2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(c) All offshore pipe in water at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water must be installed so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.

(d) Promptly after a ditch for a steel onshore transmission line is backfilled, but not later than three twelve months after placing the pipeline in service, the operator must perform an assessment to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG) or other coating assessment technique allowed by section 4 of NACE SP0502 (incorporated by reference, see § 192.7). The operator must repair any coating damage classified as moderate or severe (voltage drop greater than 35% for DCVG or 50 dBμv for ACVG) within six twelve months of the assessment. Each operator of transmission pipelines must make and retain for the life of the pipeline records documenting the coating assessment findings and repairs.

§192.461 External corrosion control: Protective coating.

(f) Promptly, but no later than three twelve months after backfill of an onshore transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), conduct surveys to assess any coating damage to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG), or other coating assessment technique allowed by section 4 of NACE SP0502 (incorporated by reference, see § 192.7). Remediate any coating damage classified as moderate or severe (voltage drop greater than 35% for DCVG or 50 dBμv for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six twelve months of the assessment.
§192.465 External corrosion control: Monitoring.

(d) Operators shall take prompt remedial action to correct any deficiencies indicated by the inspection and testing provided in paragraphs (a), (b) and (c) of this section. Remedial action must be initiated promptly, but no later than the next monitoring interval in §192.465 or within one year, whichever is less. Remedial action must be completed promptly, but no later than the next monitoring interval, but no later than one year, whichever is less.

(f) For onshore transmission lines, where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in Appendix D of this part, the operator must determine the extent of the area with inadequate cathodic protection. Close interval surveys must be conducted in both directions from the test station with a low cathodic protection (CP) reading at a minimum of approximately five foot intervals. Close interval surveys must be conducted, where practical based upon geographical, technical, or safety reasons. Close interval surveys required by this part must be completed with the protective current interrupted unless it is impractical to do so for technical or safety reasons. Remediation of areas with insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline must be performed in accordance with paragraph (d). The operator must confirm restoration of adequate cathodic protection by close interval survey over the entire area.

§192.473 External corrosion control: Interference currents.

(c) For onshore gas transmission pipelines, the program required by paragraph (a) must include:

(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be taken on a periodic basis including, when there is knowledge of current flow increases over pipeline segment grounding design, from any co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures;

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could impact the effectiveness of cathodic protection; and

(3) Implementation of remedial actions to protect the pipeline segment from detrimental interference currents. Remedial action must be completed promptly but no later than six months after completion of the survey. If the remedial action cannot be completed within twelve months, the operator shall document actions in progress to correct the interference and the expected timeframe for completion.

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

(a) For onshore transmission pipelines, each operator must develop and implement a monitoring and mitigation program to identify any potentially corrosive constituents in the gas being transported and mitigate any corrosive effects. Potentially corrosive constituents include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and free water, either by itself or in combination. Each operator must evaluate the partial pressure of each corrosive constituent by itself or in combination to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures.

(b) The monitoring and mitigation program in paragraph (a) of this section must include:

(1) At points where gas with potentially corrosive contaminants can enter the pipeline, the use of gas-quality monitoring equipment methods to determine the corrosive gas stream constituents at points where gas with potentially corrosive contaminants enters the pipeline.
(2) Product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate the potentially corrosive gas stream constituents;

(3) Evaluation twice each calendar year, at intervals not to exceed 7-½ months, of gas stream and liquid quality samples and implementation of adjustments and mitigative measures to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

c) If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked at least twice each calendar year, at intervals not exceeding 7 ½ months.

(d) Each operator must review its monitoring and mitigation program based on operators O&M Manual or at least twice once each calendar year, at intervals not to exceed 7-½ 15 months. Based on the results of its gas stream sampling and internal corrosion monitoring in (a) and (b) and implement adjustments in its monitoring for and mitigation of the potential for internal corrosion due to the presence of potentially corrosive gas stream constituents.

§192.485 Remedial measures: Transmission lines.

(a) General corrosion. Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) Localized corrosion pitting. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, see §192.7) or the procedure in PRCI PR 3-805 (R-STRENG) (incorporated by reference, see §192.7) for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the procedures, including the appropriate use of class location and pipe longitudinal seam factors in pressure calculations for pipe defects. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, and crack-related defects, appropriate failure criteria must be used and justification of the criteria must be documented.

(d) Pipe and material properties used in remaining strength calculations and the pressure calculations made under this paragraph must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgments may be used.

2. Requirements for Internal Corrosion Direct Assessment & Stress Corrosion Cracking Direct Assessment

PHMSA is proposing to change requirements regarding the use of Internal Corrosion Direct Assessment (ICDA) and Stress Corrosion Cracking Direct Assessment (SCCDA) as integrity management assessment methods
for addressing the respective threats for internal corrosion and stress corrosion cracking (SCC).\textsuperscript{80} The proposed requirements are rooted in two NACE Standards, NACE SP02506-2006: \textit{Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas} and NACE SP0204-2008: \textit{Stress Corrosion Cracking (SCC) Direct Assessment Methodology}, making the codified requirements much more prescriptive and contrary to the performance based principles of integrity management.

AGA reminds PHMSA that in the NTNB’s 2015 Safety Study, \textit{Integrity Management of Gas Transmission Pipelines in High Consequence Areas}, NTNB/SS-15/01, the NTNB acknowledged that existing corrosion control methods are effective and they recommended extending these methodologies beyond HCAs. “These observations suggest that strategies for reducing potential incidents due to corrosion and material failure appear to be effective and should be expanded to non-HCA pipelines”\textsuperscript{91}

AGA does not support the incorporation by reference, nor the required application, of standards that are not widely used and adopted by natural gas pipeline operators. Additionally, the proposed regulation goes beyond international standards such as NACE SP0204-2008 and NACE SP02506-2006, without providing the intended protections to improve internal corrosion assessments. NACE standards do acknowledge and state that specific actions and practices are not included for every circumstance due to the complexity of situations and conditions that may be encountered or required. By incorporating the NACE standards, and including specific requirements beyond the NACE standards, PHMSA is limiting what options pipeline operators have to monitor and mitigate corrosion threats. As an example, NACE SP0206-2006 defines DG-ICDA Region as “A continuous length of pipe (including weld joints) uninterrupted by any significant change in water or flow characteristics that includes similar physical characteristics or operating history.” The additional criteria and definition included in the Proposed Rule is very prescriptive, and an operator may select regions based on their knowledge about the system beyond just input. AGA therefore suggests PHMSA maintain existing regulatory code language and remove the newly introduced methodology. In Appendix A of these comments, AGA recommends regulatory language modifications to allow for ASME/ANSI B31.8S, Section 6.4 and Appendix B2 for ICDA and ASME/ANSI B31.8S Appendix A3.3 for SCCDA, as an alternative to NACE SP0206-2006 and NACE SP0204-2008 respectively. It should be noted that intrastate transmission lines may have mixing of gases from more than one region, which make it harder to separate dry gas regions. AGA does not offer any changes to the proposed regulation but would appreciate this acknowledgement within the preamble language of the final rule.

In the PRIA, PHMSA states that:

“These standards have been used successfully since the mid-2000s, and are the best available guidance. Most operators already successfully utilize these standards when conducting these types of assessments. Therefore, incremental cost to operators from incorporating these standards by reference in the pipeline safety regulations would be negligible compared to the cost of the additional scope described in Section 3.2.”\textsuperscript{92}

Only approximately one-third of AGA members fully incorporate NACE SP0206-2006 into their operational procedures. Generally, AGA members use a modified version of this standard to address the unique circumstances

\textsuperscript{80} See Fed. Reg. at 20817.
\textsuperscript{91} NSTB Safety Study, NTNB/SS-15/01 PB2015-102735 Notation 8565A Adopted January 27, 2015, Integrity Management of Gas Transportation Pipelines in High Consequence Areas, page 23,
\textsuperscript{92} PRIA. Page 72.
of their pipeline systems in regards to these threats. The cited NACE standards are more theoretical than field-practical, while existing practices have been proven to be effective. By using prescriptive wording requiring NACE SP0206-2006 defined DG-ICDA Regions, PHMSA is prohibiting operators from using additional criteria specific to the operator. For example, the NACE SP0206-2006 standard requires additional “sub-region” digs to account for periods of low-flow that may or may not be applicable to operator’s lines. This will result in an increase in ICDA direct exams by as much as 67 percent for many operators. AGA, therefore, strongly opposes PHMSA’s general conclusion that the strict incorporation of these standards would have negligible impact. If PHMSA proceeds as proposed, AGA requests that these costs be incorporated in the Regulatory Impact Assessment for the Final Rule.

Finally, AGA recommends that PHMSA remain consistent in the language used to reference spike testing and as discussed throughout these comments, allow for supported, sound engineering judgments to be utilized while operators are meeting the requirements of §192.607 Material Verification.

Below are AGA’s recommended changes to PHMSA’s proposed regulatory language. These changes meet PHMSA’s intent to improve pipeline safety in a manner that is reasonable and effective. These changes can also be found in Appendix A of AGA’s comments:

§192.3 Definitions.

Dry gas or dry natural gas means gas with less than 7 pounds of water per million (MM) cubic feet and not typically subject to excessive upsets allowing electrolytes into the gas stream.

§192.923 How is direct assessment used and for what threats?

(a) General. An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (EC), internal corrosion (IC), and stress corrosion cracking (SCC).

(b) Primary method. An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in—

1. Section 192.925 and ASME/ANSI B31.8S (incorporated by reference, see §192.7) section 6.4, and NACE SP0502 (incorporated by reference, see §192.7), if addressing external corrosion (EC).

2. Section 192.927, and ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.4, appendix B2 or NACE SP0206-2006 if addressing internal corrosion (ICDA).

3. Section 192.929, and ASME/ANSI B31.8S (incorporated by reference, see §192.7), appendix A3 or NACE SP0204-2008 if addressing stress corrosion cracking (SCCDA).

(c) Supplemental method. An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in §192.931.

§192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(a) Definition. Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal
corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO₂, O₂, hydrogen sulfide or other contaminants present in the gas.

(b) General requirements. An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206-2006 or ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.4 and appendix B2. The Dry Gas (DG) ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas (see definition §192.3), and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment in accordance with §192.921 (a)(4) or §192.937(c)(4).

c) The ICDA plan. An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring and meets all requirements and recommendations contained in NACE SP0206-2006 and that implements all four steps of the DG-ICDA process including pre-assessment, indirect inspection, detailed examination, and post-assessment. The plan must identify where all ICDA Regions with covered segments are located in the transmission system. An ICDA Region is a continuous length of pipe (including weld joints) uninterrupted by any significant change in water or flow characteristics that includes similar physical characteristics or operating history. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located in order to complete the assessment of the covered segment.

(1) Preassessment. An operator must comply with the requirements and recommendations in NACE SP0206-2006 in conducting the preassessment step of the ICDA process. gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to—

(i) All data elements listed in appendix A2 of ASME/ANSI B31.8S;

(ii) Information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (See paragraph (a) of this section.) This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline;

(iii) Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and

(iv) Information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.

(2) ICDA region identification. An operator’s plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location
where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02-0057, “Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology,” (incorporated by reference, see §192.7). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02-0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations down stream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas. An operator must comply with the requirements and recommendations in NACE SP0206-2006, and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. Operators must explicitly document the results of its feasibility assessment as required by NACE SP0206-2006, Section 3.3; if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use pipeline specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of data used to make those calculations, including but not limited to gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossing, river crossings, drains, valves, drips, etc.), topographical data, depth of cover, etc. The operator must select locations for direct examination, and establish the extent of pipe exposure needed (i.e., the size of the bell hole), to explicitly account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

(3) Identification of locations for excavation and direct examination. An operator’s plan must identify the locations where internal corrosion is most likely in each ICDA region. An operator must comply with the requirements and recommendations in NACE SP0206-2006 in conducting the detailed examination step of the ICDA process. In addition, on the first use of ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each ICDA Region and must perform a detailed examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must—

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with §192.933; if the condition is in a covered segment, or in accordance with §§ 192.485 and 192.713 if the condition is not in a covered segment;

(ii) Expand the detailed examination program, whenever internal corrosion is discovered, to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the
beginning of the ICDA Region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined per paragraph (3) of this section, two additional detailed examinations must be conducted within the covered segment; and

(iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with §192.933 or §192.713, as appropriate.

(4) *Post-assessment evaluation and monitoring.* An operator’s plan must **comply with the requirements and recommendations in NACE SP0206-2006 in performing the post assessment step of the ICDA process.**

provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. In addition the post-assessment requirements and recommendations in NACE SP0206-2006, the evaluation and monitoring process includes—

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in §192.939. An operator must carry out this evaluation within a year of conducting an ICDA;

(ii) Validation of the flow modeling calculations by comparison of actual locations of discovered internal corrosion with locations predicted by the model (if the flow model cannot be validated, the ICDA is not feasible for the segment); and

(iii) Continually monitoring each ICDA region which contains a covered segment where internal corrosion has been identified using techniques such as coupons or UT sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the ICDA region. At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7½ months. If an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with § 192.933.

(A) Conduct excavations of, and detailed examinations at, locations downstream from where the electrolyte might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of §192.478; or

(B) Assess the covered segment using ILI tools capable of detecting internal corrosion or another integrity assessment method allowed by this subpart.

(5) *Other requirements.* The ICDA plan must also include the following:

(i) Criteria an operator will apply in making key decisions (e.g., ICDA feasibility, definition of ICDA Regions and Sub-regions, conditions requiring excavation) in implementing each stage of the ICDA process;

(ii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of §192.933 may be limited to covered segments.
§192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

(a) **Definition.** Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

(b) **General requirements.** An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must develop and follow an SCCDA plan that, at minimum, — meets all requirements and recommendations contained in NACE SP0204-2008 and that implements all four steps of the SCCDA process including pre-assessment, indirect inspection, detailed examination and post-assessment. As specified in NACE SP0204-2008, Section 1.1.7, SCCDA is complementary with other inspection methods such as in-line inspection (ILI) or hydrostatic testing and is not necessarily an alternative or replacement for these methods in all instances. In addition, the plan must provide for—

1. **Data gathering and integration.** An operator’s plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment in accordance with NACE SP0204-2008, Sections 3 and 4, and Table 1. This process must also include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations (both within and outside covered segments) where the criteria in ASME/ANSI B31.8S (incorporated by reference, see §192.7), appendix A3.3 or NACE SP0204-2008, Section 5.3 indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204-2008, Section 5.3, and must include, at minimum, the data specified in ASME/ANSI B31.8S, appendix A3 or data listed in NACE SP0204-2008, Table 2. Further the following factors must be analyzed as part of this evaluation:
   
   (i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment such as soil temperature, moisture, the presence or generation of carbon dioxide, and/or Cathodic Protection (CP).
   
   (ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments.
   
   (iii) The effects of variations in applied CP such as overprotection, CP loss for extended periods, and high negative potentials.
   
   (iv) The effects of coatings that shield CP when disbonded from the pipe.
   
   (v) Other factors which affect the mechanistic properties associated with SCC including but not limited to historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.

2. **Assessment method.** The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4 or, in addition to the requirements and recommendations of NACE SP0204-2008, section 4. The plan’s procedures for indirect inspection must include provisions for conducting at least two above ground surveys using complementary measurement tools most appropriate for the pipeline segment based on the data gathering and integration step.
(3) **Direct examination.** In addition to the requirements and recommendations of NACE SP0204-2008, the plan’s procedures for direct examination must provide for conducting a minimum of three direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur.

(4) **Remediation and mitigation.** If any indication of SCC is discovered in a segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Removing the pipe with SCC, remediating the pipe with a Type B sleeve, hydrostatic testing in accordance with (b)(4)(ii), below, or by grinding out the SCC defect and repairing the pipe. If grinding is used for repair, the repair procedure must include: nondestructive testing for any remaining cracks or other defects; measuring remaining wall thickness; and the remaining strength of the pipe at the repair location must be determined using ASME/ANSI B31G or RSTRENG and must be sufficient to meet the design requirements of subpart C of this part. Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgements may be used.

(ii) Significant SCC must be mitigated using a spike pressure test in accordance with §192.506. The maximum allowable operating pressure will be equal to the test pressure specified in §192.506(c) divided by the greater of 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or 192.620(a)(2)(ii). Hydrostatic testing program to a minimum test pressure equal to 105 percent of the specified minimum yield strength of the pipe for 30 minutes immediately followed by a pressure test in accordance with §192.506, but not lower than 1.25 times MAOP. The test pressure for the entire sequence must be continuously maintained for at least 8 hours, in accordance with §192.506 and must be above the minimum test factors in §§ 192.506(c) or 192.619(a)(2)(ii) or 192.620(a)(2)(ii), but not lower than 1.25 times maximum allowable operating pressure. Any test failures due to SCC must be repaired by replacement of the pipe segment, and the segment re-tested until the pipe passes the complete test without leakage. Pipe segments that have SCC present, but that pass the pressure test, may be repaired by grinding in accordance with paragraph (b)(4)(i).

(5) **Post assessment.** In addition to the requirements and recommendations of NACE SP0204-2008, sections 6.3, periodic reassessment, and 6.4, effectiveness of SCCDA, the operator’s procedures for post assessment must include development of a reassessment plan based on the susceptibility of the operator’s pipe to SCC as well as on the mechanistic behavior of identified cracking. Reassessment intervals must comply with section 192.939 of this part. Factors that must be considered include, but are not limited to:

(i) Evaluation of discovered crack clusters during the direct examination step, in accordance with NACE RP0204-2008, sections 5.3.5.7, 5.4, and 5.5;

(ii) Conditions conducive to creation of the carbonate-bicarbonate environment;

(iii) Conditions in the application (or loss) of CP that can create or exacerbate SCC;

(iv) Operating temperature and pressure conditions including operating stress levels on the pipe;

(v) Cyclic loading conditions;

(vi) Mechanistic conditions that influence crack initiation and growth rates;

(vii) The effects of interacting crack clusters;
The presence of sulfides; and.
Disbonded coatings that shield CP from the pipe.

3. 49 C.F.R. Part 192 Appendix D – Criteria for Cathodic Protection and Determination Measurements

PHMSA is proposing to modify Appendix D to Part 192: *Criteria for Cathodic Protection and Determination of Measurements*. PHMSA believes the contents of the appendix, which outline how operators monitor levels of cathodic protection to ensure adequate protection on piping systems, are outdated and misaligned with current industry standards. See 81 Fed. Reg. 20820. AGA does not support these changes as they are unsubstantiated, reflect earlier industry knowledge and standards, and are unnecessary. In addition, while PHMSA asserts that the changes would only apply to gas transmission and gathering lines, in fact, the changes to Appendix D would also impact distribution, because Appendix D currently applies to gas distribution systems. Distribution operators follow Appendix D criteria for cathodic protection, and unless PHMSA explicitly exempts distribution from the changes, the agency must provide a rational basis for its decision and demonstrate why imposing these changes on distribution are justified. Once again, PHMSA has made no attempt to fulfill this basic requirement of administrative law.

In a proposed regulation focused on meeting Congressional Mandates and NTSB recommendations, AGA questions why PHMSA has tried to modify pipeline safety regulations that were not included in these areas. To the best of AGA’s knowledge, there is no outstanding Congressional mandate or NTSB recommendation to change pipeline safety corrosion requirements. Therefore, AGA believes PHMSA’s changes to Appendix D are unnecessary and will be unduly burdensome to all pipeline operators, transmission and distribution, with no substantiated safety benefit. In the NTSB study, *Integrity Management of Gas Transportation Pipelines in High Consequence Areas*, they acknowledged that existing corrosion control methods are effective and recommended extending these methodologies beyond HCAs. The NTSB stated “these observations suggest that strategies for reducing potential incidents due to corrosion and material failure appear to be effective” and “strategies should be developed to reduce other failure causes, such as equipment failure and excavation damage, in all pipelines”93. Additionally, 49 U.S. Code § 60102 - Purpose and general authority, (l) Updating Standards requires that industry standards that have been adopted as part of the Federal pipeline safety regulatory program should be deemed appropriate and practicable. PHMSA’s adoption of NACE standards - while eliminating certain methodologies still contained within those and other NACE standards - is contrary to the intent and purpose this requirement.

The science behind proven corrosion prevention and control methodologies has not changed. Although PHMSA has stated a desire to “better align with current standards” in the Proposed Rule94, PHMSA provided no indication of the standards being referenced, and PHMSA failed to provide any other justification for the proposed change. With advances in technology, equipment and tools, these time-proven methodologies have become more effective and efficient at controlling and preventing corrosion. Therefore, the methodologies proposed to be eliminated, such as the replacement of galvanic systems with impressed current systems or the 300 millivolt shift, are not “outdated” and their elimination is not in alignment with current effective industry practices.

93 NSTB Safety Study, NTSB/SS-15/01 PB2015-102735 Notation 8565A Adopted January 27, 2015, Integrity Management of Gas Transportation Pipelines in High Consequence Areas
As explained below, the removal of these criteria would impose significant costs without improving safety. The proposed changes would require operators to use unwarranted and extremely burdensome methods of compliance, and these changes would disproportionately affect the operation of distribution and intrastate transmission pipelines compared to interstate transmission pipelines.

One example of an unwarranted change and resulting burden of PHMSA’s proposed modification to Appendix D is the resultant elimination of galvanic systems. The cost of replacing existing galvanic systems with impressed current systems, as implied by the proposed regulatory changes, would be prohibitive and would divert funds and resources away from more useful and appropriate pipeline safety activities, such as cast iron replacement programs. Removal of these cathodic protection systems would require operators of distribution pipelines to install more test stations. PHMSA has grossly under estimated the cost of test stations in table 3-73 in the PRIA. AGA members estimate each test station could cost up to $22,000, in paved areas, and PHMSA estimates a cost of only $500 per test station. PHMSA estimates test stations would be required at distances of approximately ½ mile intervals in HCA and shorter distances would be required in urban areas due to other underground structures. Using PHMSA’s own estimate of 19,872 miles of HCA transmission pipe with 2 test stations every mile and approximately 80% of the test stations already in place, additional test stations would cost the industry over $174,873,600 instead of the $3,974,492 PHMSA estimates. Costs would be considerably more for distribution lines with test stations spaced less than every half mile.

Additionally, some operators have long used the 300 mV shift and E-log-I curves to demonstrate corrosion control compliance. Removal of these cathodic protection criteria would require modifications of test stations and other cathodic protection materials and equipment. E-log-I curves are also used to determine cathodic protection on well casings. Eliminating this methodology removes the only effective method to determine cathodic protection for such applications.

With galvanic systems, only individual test stations can be turned off for surveys. This may not present issues for interstate transmission operators. However, most distribution operators and intrastate transmission operators have a combination of impressed current systems and galvanic systems. Eliminating certain methodologies would require significant modifications to existing corrosion protection/prevention systems. An alternative could be to allow distribution and intrastate operators to continue to take surveys with cathodic protective systems operating “On.” In addition, transmission operators with pipelines where ECDA is the only assessment option available to address the threat of External Corrosion would need to disconnect all magnesium anodes and install impressed current systems to address the new definition of a close interval survey that quantifies IR drop. This would be a time and resource intensive process without substantiated benefits to safety.

In the current code, IR drop must be considered; however, in the proposed code, IR drop is to be measured and differentiated. The determination of how IR drop is differentiated is unexplained in the Proposed Rule. Determining and measuring IR drop would require additional test stations with an additional cost impact without substantiated benefits to safety. These additional costs and impacts were not considered by PHMSA in the PRIA.

AGA therefore urges PHMSA to revise its proposed changes to Appendix D of Part 192. AGA’s proposed changes are listed below and can also be found in Appendix A of these comments.
Appendix D to Part 192 – Criteria for Cathodic Protection and Determination Measurements

I. Criteria for cathodic protection—
   A. Steel, cast iron, and ductile iron structures.
      (1) A negative (cathodic) voltage across the structure electrolyte boundary of at least 0.85 volt, with reference to a saturated copper-copper sulfate reference electrode, often referred to as a half cell. Determination of this voltage must be made in accordance with sections II and IV of this appendix.
      (2) A minimum negative (cathodic) polarization voltage shift of at least 300 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.
      (3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.
      (4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.
      (5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.
   B. Aluminum structures.
      (1) Except as provided in paragraphs (2) and (3) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 150 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.
      (2) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.
      (3) Notwithstanding the alternative minimum criteria in paragraph s (1) and (2) of this paragraph, if aluminum is cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate reference electrode, in accordance with section IV of this appendix, the aluminum may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.
      (4) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.
   C. Copper structures. A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.
   D. Metals of different anodic potentials. A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (2) and (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. Interpretation of voltage measurement. Structure-to-electrolyte potential measurements must be made utilizing measurement techniques that will minimize voltage (IR) drops other than those across the
structure-electrolyte boundary. All voltage (IR) drops other than those across the structure electrolyte boundary will be differentiated, such that the resulting measurement accurately reflects the structure-to-electrolyte potential.

III. Determination of polarization voltage shift. The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs often referred to as an instant off potential. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(2), B(1), and C of section I of this appendix.

IV. Reference electrodes (half cells).
A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate reference electrode contacting the electrolyte.
B. Other standard reference electrodes may be substituted for the saturated copper-copper sulfate electrode. Two commonly used reference half cells electrodes are listed below along with their voltage equivalent to −0.85 volt as referred to a saturated copper-copper sulfate reference electrode:
   (1) Saturated KCl calomel half cell: −0.78 volt.
   (2) Silver-silver chloride reference electrode used in sea water: −0.80 volt.
C. In addition to the standard reference electrodes, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate reference electrode if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate reference electrode is established.

L. Continuing Surveillance After Extreme Weather Events

PHMSA has proposed a new requirement for operators to inspect all “potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline” following an extreme weather event or other similar event. See proposed 49 C.F.R. § 192.613(c). PHMSA has consistently distributed Advisory Bulletins on an annual basis to operators warning about extreme weather events and the necessity to inspect pipelines once it is safe to do so. AGA agrees that it is prudent for operators to perform patrols of at-risk pipelines and facilities following an extreme weather event when the operator has reason to believe there is a reasonable likelihood that the extreme weather event may have affected its system. However, AGA believes that the proposal is duplicative to existing regulations and requirements for emergency response and patrolling procedures and plans. Furthermore, AGA is concerned that the broad applicability of the proposal, coupled with the prescriptive inspection requirements, would require the inspection of pipelines during times when personnel are focused on emergency response, exposed to greater safety risks related or unrelated to its system, and could require numerous unnecessary inspections. AGA encourages PHMSA to recognize the duplicative nature of this proposal, and, at a minimum, revise the proposed requirements to provide operators with a greater level of discretion in determining when to patrol pipelines.

AGA is concerned with how the proposed requirements for inspections following extreme weather events would relate to the existing emergency response regulations. Pursuant to §192.605, operators are required to prepare and follow written procedures for conducting operations and maintenance activities and for emergency response. See 49 C.F.R. § 192.605(a). Under §192.615(a), an operator’s manual must include procedures to
minimize the hazard resulting from a natural gas pipeline emergency, which includes a natural disaster.\textsuperscript{95} These procedures must address the prompt and effective response to natural disasters as well as the availability of personnel, equipment, tools, and materials. Id. at §192.615(a). Many of the requirements in proposed §192.613(c), such as pressure reductions and coordinating with emergency personnel, are duplicative of what is currently required of operators in their emergency response plans. As a result, AGA believes that the proposed inspection requirements are duplicative and may conflict with existing regulation, resulting in an increase in regulatory uncertainty rather than advancing pipeline safety.

Should PHMSA decide that explicit changes to the Pipeline Safety Code are necessary to address extreme weather events, AGA provides the following comments.

\textit{Applicability}

PHMSA has proposed required inspections and possible remedial actions following “an extreme weather event such as a hurricane or flood, an earthquake, landslide, a natural disaster, or other similar event that has the likelihood of damage to infrastructure.” See proposed §192.613(c). AGA is concerned that this applicability fails to recognize the diverse environments that natural gas pipelines operate within, and that in some locations, these events are not considered extreme, but instead are part of the normal working environment to which pipelines are designed and constructed to operate safely. As such, AGA suggests that PHMSA revise the applicability to put the responsibility on the operator to determine when such an event has occurred. This will allow a case-by-case determination, specific to the environment of the pipeline system, to determine whether inspection is required.

AGA also is concerned with the broad requirement for the “inspection” of “all potentially affected onshore transmission pipeline facilities.” Following an extreme weather event, a prudent operator is going to patrol the pipeline right-of-way looking for both evidence of pipe exposures or damages to above ground pipeline facilities in accordance with §192.705. As a result of the patrol, if damage is suspected, then the operator will conduct further examinations as necessary (or appropriate) to ensure the safety of the pipeline. This understanding is consistent with PHMSA’s statements in the PRIA suggesting that there will be no additional cost due to patrols, because “most operators already have right-of-way inspection, surveillance, and leakage survey procedures.” See PRIA, page 92. However, AGA is concerned that the proposed language could be interpreted as requiring physical excavation and inspection of the pipeline, or the undertaking an in-line inspection, following an extreme weather event. AGA believes this is not PHMSA’s intent based on PHMSA’s description of the impact in the PRIA, but the regulatory language could be interpreted otherwise. AGA encourages PHMSA to revise the regulatory text to require “patrols” of pipeline rights-of-way and above-ground pipeline facilities.

During the June 7, 2016 webinar PHMSA held in connection with this rule, PHMSA’s presentation described the inspection as requiring a visual inspection plus in-line inspection of “other.” See Webinar Presentation, slide 15. There is no proposal or statements in the proposed regulatory text, preamble, or PRIA that such a combination of inspections would be required. As noted above, a prudent operator will patrol the right-of-way to make a visual inspection and then determine what, if any, additional inspections or assessments would be necessary. AGA assumes that slide 15 from the webinar presentation is incorrect. If AGA’s assumption is incorrect and PHMSA continue with its position that, in addition to a visual inspection, an operator would always need to

\textsuperscript{95} PHMSA’s presentation during the June 8, 2016 webinar held in connection with this rulemaking incorrectly states that “current rules do not address extreme events that can damage pipelines or disrupt operations.” NPRM: Safety of Gas Transmission & Gathering Pipelines Presentation (Webinar Presentation), page 15.
perform an additional inspection, possibly ILI, than significant revisions would need to be made to the proposed regulatory text and burden within the PRIA. Moreover, AGA points out the impracticability of arranging for vendors and conducting an in-line inspection on all pipelines after every extreme weather event and within the 72-hour proposed window.

**Timing**

PHMSA has proposed that the patrol commence within 72 hours after the cessation of the extreme weather event, defined as when the affected area can be safely accessed by the personnel and equipment. See proposed §192.613(c)(2). AGA encourages PHMSA to remove the 72-hour time period and instead require that inspections commence as soon as reasonably practicable given the potential impact on the system and other potentially greater safety concerns both related and unrelated to its system. After an extreme weather event, operating companies should be focused on the safety of the public, employees, and integrity of company assets, not an arbitrary timeline within federal regulations. By eliminating the 72-hour reference and focusing on safety, the regulation would appropriately place the responsibility on operators to evaluate and determine when it is safe for personnel and equipment to perform the inspections.

Additionally, the proposed surveillance requirements are to begin after the cessation of the weather event, “defined as the point in time when the affected area can be safely accessed by the personnel and equipment, including availability of personnel and equipment, required to perform the inspection as determined under paragraph (c)(1) of this section, whichever is sooner.” See proposed §192.613(c)(2) (emphasis added). AGA agrees with PHMSA that operating personnel should not be required to enter unsafe areas, but they should also not be distracted from ongoing emergency response activities. The “whichever is sooner” language would imply that if the personnel are available but it is not yet safe, an operator would be required to send personnel to the unsafe area to conduct an inspection.

**Justification and Estimated Impacts**

Based on the above and the inconsistencies between the Proposed Rule, PRIA, and PHMSA’s webinar, the proposal lacks the reasoned justification necessary to support its decision. According to PHMSA, based on recent examples of extreme weather events that did result or could have resulted in pipelines incidents, PHMSA has determined that additional requirements are necessary. See 81 Fed. Reg. 20812. However, PHMSA has failed to provide any analysis or reasoning linking the proposed requirements with its general “determination” that additional requirements are necessary. Similarly absent is any explanation as to how PHMSA’s proposal, would address the identified concerns.

PHMSA has estimated the impact and benefits associated with the proposed inspections following extreme weather events in the PRIA. There are several inaccuracies with PHMSA’s analysis in the PRIA that make it difficult to evaluate PHMSA’s proposal as well as provide meaningful comment. First, the PRIA incorrectly states that the proposed inspection following extreme weather events would apply to both onshore and offshore pipelines and that §192.613(a) would be modified. See PRIA, page 92. According to the proposed regulatory text, the proposed inspection would only apply to onshore transmission pipelines and §192.613(a) is not proposed to be modified.

Second, PHMSA’s estimate of the regulatory impact associated with reviewing existing surveillance and patrol procedures to validate adequacy for extreme weather events estimates the low number of hours as 2 hours...
and the high number of hours as 1 hour. PHMSA estimates the costs based on these numbers. There is a clear error in PHMSA’s estimates, since the high-side estimate is 50% lower than the low-side estimate. See PRIA Table 3-78, page 92-93.

Third, PHMSA’s description in the PRIA of when the surveillance must occur differs from that in the proposed regulatory text. The PRIA states that surveillance must occur “within 72 hours of the cessation of an event or as soon as possible once personnel and equipment can safely access the area.” See PRIA, page 92. As noted above, the regulatory text defines the “cessation of the event” as when the area can be accessed safely, and provides operators 72 hours from that point to conduct the surveillance.

PHMSA has justified this new requirement due to the learnings from an October 1994 incident and the 85 reportable incidents from 2003 to 2013 “in which storms or other severe natural force conditions damaged pipelines and resulted in their failure.” However, from the incident data provided in the PRIA, it is impossible for stakeholders to evaluate to which 85 incidents PHMSA is referring or evaluate the appropriateness of inclusion. PHMSA’s estimate of the related benefits is significantly lacking. PHMSA estimates that 0.5 incidents will be averted each year due to these proposed requirements. PHMSA’s assumption is based solely on PHMSA’s best professional judgment, with no elaboration on where the 0.5 figure came from. From this, and PHMSA’s general estimate on the cost of an incident, PHMSA estimates annual benefits of the proposed requirements. Such an unsupported estimate is in essence no estimate at all and cannot satisfy PHMSA’s statutory obligation to consider the reasonably identifiable or estimated benefits. Based on these inaccuracies and omissions, it is not possible for stakeholders to provide meaningful comment on PHMSA’s proposed regulatory impact.

Based on the above comments, AGA encourages PHMSA to eliminate the proposed inspections after extreme weather events, or in the alternative, make the following changes:

§192.613 Continuing surveillance

(c) Following an extreme weather event such as a hurricane or flood, an earthquake, landslide, a natural disaster, or other similar event, which in the operator’s judgment has the likelihood of damage to infrastructure, an operator must inspect patrol pipeline right-of-ways and above ground facilities of all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

(1) Patrol inspection method. An operator must consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial patrol inspection to determine damage and the need for the additional assessments required under the introductory text of paragraph (c) in this section.

(2) Time period. The patrol inspection required under the introductory text of paragraph (c) of this section must commence within 72 hours after the cessation of the event, defined as the point in time should commence as soon as practicable considering when the affected area can be safely accessed by the personnel and equipment, taking into account the availability of personnel and equipment, required to perform the patrol inspection as determined under paragraph (c)(1) of this section, whichever is sooner.

97 AGA’s significant concerns related to PHMSA’s estimated average cost per incident are discussed in Section V.
(3) Remedial action. An operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the patrol inspection required under the introductory paragraph (c) in this section. Such actions might include, but are not limited to:

i. Reducing the operating pressure or shutting down the pipeline;
ii. Modifying, repairing, or replacing any damaged pipeline facilities;
iii. Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;
iv. Performing additional patrols, surveys, tests, or inspections;
v. Implementing emergency response activities with Federal, State, or local personnel; or
vi. Notifying affected communities of the steps that can be taken to ensure public safety.

M. Gathering Lines

PHMSA has introduced new definitions, added classifications, and has significant expanded requirements for gas gathering lines. AGA believes further consideration by PHMSA is necessary before any of these changes are incorporated into the Final Rule. AGA generally supports the comments submitted by American Petroleum Institute (API), the Independent Petroleum Association of America (IPAA), the Gas Processors Association (GPA) and the Texas Pipeline Association (TPA) in their comments on gas gathering pipelines.

AGA would like to further emphasize the importance of regulatory clarity. In the proposed §192.9(c) PHMSA states, “an operator of a Type A, Area 1 regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in ...” Therefore, operators are left to assume that all regulatory requirements for gas transmission lines are to be applied to Type A, Area 1 gas gathering lines unless specifically excluded. This is especially concerning given the significant new and modified requirements for gas transmission pipelines within the Proposed Rule. In Table 3.M-1 below, AGA provides a listing of sections within 49 C.F.R. 192 where AGA believes PHMSA should provide additional clarity on the requirements for gas gathering lines:

<table>
<thead>
<tr>
<th>49 C.F.R. 192 Section</th>
<th>AGA Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>§192.3 Definitions</td>
<td>Moderate Consequence Areas: Due to the fact that MCAs are defined within the general definition section, one could interpret a requirement for operators to perform a MCA analysis on all pipelines, not just those that are applicable to the requirements where MCAs are referenced. PHMSA should explicitly state that gathering lines are not required to perform an MCA analysis.</td>
</tr>
<tr>
<td>Rule Number</td>
<td>Description</td>
</tr>
<tr>
<td>-------------</td>
<td>-------------</td>
</tr>
<tr>
<td>§192.13</td>
<td>General Requirements</td>
</tr>
<tr>
<td>§192.67</td>
<td>Records: Materials</td>
</tr>
<tr>
<td>§192.127</td>
<td>Records: Pipe design</td>
</tr>
<tr>
<td>§192.205</td>
<td>Records: Pipe components</td>
</tr>
<tr>
<td>§192.227(c)</td>
<td>Welding Record Requirements</td>
</tr>
<tr>
<td>§192.285(c)</td>
<td>Plastic Pipe Joining</td>
</tr>
<tr>
<td>§192.485(c)</td>
<td>Remedial measures: Gas Transmission lines</td>
</tr>
<tr>
<td>§192.607</td>
<td>Material Verification</td>
</tr>
<tr>
<td>§192.613</td>
<td>Continuing Surveillance</td>
</tr>
</tbody>
</table>
| §192.624  
MAOP Verification | As discussed on the June 8, 2016 PHMSA Webinar on the Proposed Rule, to meet PHMSA’s intent and estimated impact in the PRIA of this proposed rule, PHMSA should exclude gas gathering lines from this new requirement intended only for gas transmission pipelines. |
| §192.711(b)(1)  
Non-Integrity management repairs | By proposing a more prescriptive repair timeline and referencing proposed §192.713, PHMSA has introduced very prescriptive and stringent repair criteria for gas gathering lines. AGA does not believe this was PHMSA’s intent and therefore recommends that PHMSA explicitly exclude gas gathering pipelines from §192.711(b)(1). AGA supports the continued compliance with the remainder of §192.711 for gas gathering lines. |

For the reasons listed above, AGA recommends the following modifications to §192.9(c):

(a) **Type A lines, Area 1 Lines.** An operator of a Type A, Area 1 regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§192.13(d) and (e), 192.67, 192.127, 192.150, 192.205, 192.227(c), 192.285(c), 192.319, 192.461(f), 192.465(f), 192.473(c), 192.478, 192.485(d), 192.607, 192.613, 192.624, 192.711(b)(1), 192.710, 192.713, [or AGA’s proposed Subpart Q] and in subpart O of this part. However, an operator of a Type A, Area 1 regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

The concerns described above are also applicable to Type A, Area 2 and Type B gathering lines that are addressed in §192.9(d). PHMSA has failed to maintain their position within §192.9(c) that gathering lines should be exempt from specific pipeline safety requirements for transmission pipelines, Type A, Area 1 pipelines are considered to be higher risk than Type A, Area 2, and therefore the same exemptions should apply. Therefore, AGA encourages the following changes to §192.9(d):

(b) **Type A, Area 2 and Type B lines.** An operator of a Type A, Area 2 or Type B regulated onshore gathering line must comply with the following requirements:

1. If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines, except the requirements in §§192.13(d) and (e), 192.67, 192.127, 192.150, 192.205, 192.227(c), 192.285(c), 192.319, 192.461(f), 192.465(f), 192.473(c), 192.478, 192.485(d), 192.607, 192.613, 192.624, 192.711(b)(1), 192.710, 192.713, [or AGA’s proposed Subpart Q] and in subpart O of this part;

2. If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except the requirements of §§192.461(f), 192.465(f), 192.473(c), 192.478, and 192.485(d);

Also, AGA would like to call PHMSA’s attention to the discrepancies between §192.9(e) and §192.13(a)(2) and (b). In §192.9(e), PHMSA allows two years after the effective date of the rule for pipelines that were not
previously subjected to Part 192 to comply with all applicable sections. However, in the tables within §192.13(a) and (b), PHMSA provides only one year after the effective date of the rule. AGA encourages regulatory and consistency between these two sections and suggests that operators be given two years given the incredible amount of pipeline mileage that will now be subject to additional regulatory requirements. AGA provides the following recommended changes to the proposed §192.13 language to resolve this discrepancy.

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

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

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore gathering line</td>
<td>July 31, 1977.</td>
</tr>
<tr>
<td>Regulated onshore gathering line to which this part did not apply until April 14, 2006</td>
<td>March 15, 2007.</td>
</tr>
<tr>
<td>Regulated onshore gathering line to which this part did not apply until (insert effective date of the rule)</td>
<td>(Insert effective date of the rule plus one two years).</td>
</tr>
<tr>
<td>All other pipelines</td>
<td>November 12, 1970.</td>
</tr>
</tbody>
</table>

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

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<tr>
<td>All other pipelines</td>
<td>November 12, 1970.</td>
</tr>
</tbody>
</table>

PHMSA is also proposing under section §191.23 (Reporting safety-related conditions), to require reporting of safety related conditions for all gathering lines. However, AGA believes the requirements should be modified to only require reporting of Safety Related Conditions for Type A and Type B regulated gathering lines as defined in 49 C.F.R. §192.8. By including reporting requirements related to both MAOP exceedance and corrosion monitoring, PHMSA is proposing to subject the still non-regulated gathering facilities to reporting requirements
relating to provisions that are not applicable to those facilities. AGA provides the following changes to §192.23 to ensure regulatory clarity.

§191.23 Reporting safety-related conditions.

(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with §191.25 the existence of any of the following safety-related conditions involving facilities in service:

(1) Any malfunction or operating error that causes the pressure of a distribution, Type A, or Type B gathering pipeline or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the margin (build-up) allowed for operation of pressure limiting or control devices.

Finally, as described in detail in API’s comments and in the ICF International Study, AGA has serious concerns about PHMSA’s estimate of impact for gas gathering lines. AGA understands this is largely due to discrepancies between the proposed regulatory text, and PHMSA’s intent for gas gathering lines. However, this confusion should not and cannot continue when the Final Rule is published. AGA further discusses these concerns in Section V of these comments on PHMSA’s PRIA.

N. 49 C.F.R. Part 192 Incorporations by Reference

PHMSA’s Proposal to Incorporate Industry Consensus Standards by Reference

AGA provides PHMSA with the following comments on its proposal to revise documents incorporated by reference into Part 192.

Recommendations Contained Within Consensus Standards

PHMSA has proposed to revise the Incorporations by Reference (IBR), §192.7, for Part 192 to reflect changes found within the Proposed Rule. See 81 Fed. Reg. 20807. AGA does not support PHMSA’s proposal to incorporate by reference “recommendations” found within industry consensus standards. PHMSA has failed to provide justification for these inclusions or for this departure from its prior position of limiting the portions of consensus standards incorporated by reference to those portions that include “requirements.” PHMSA’s proposal to mandate “recommendations” contained in the following proposed IBR documents should be deleted: § 192.150 (SP0102-2010), §192.493 (API STD1163, ASNT ILI-PQ-2005, SP0102-2010), §192.927 (SP0206-2006), and §192.929 (SP0204-2008).

Historically, when incorporating consensus standards, PHMSA has stated only that the “requirements” of the consensus standard shall be followed. This allows the operator the flexibility to use other practices if a consensus standard recommendation is not practical or an operator has other practices that meet the intent of the “recommendation.” However, in the Proposed Rule, PHMSA states that the incorporation by reference would require the operator to meet both the “requirements and recommendations” of a document incorporated into Part 192. See 81 Fed. Reg. 20811 (emphasis added). PHMSA has not provided justification in its Proposed Rule as

98 AGA addresses its concerns with revisions to a specific document in the detailed comments throughout AGA’s comments.
to why it is deviating from its past practice of stating only that the “requirements” of a consensus standard must be followed.

Consensus standards are written and approved by the members of the consensus organization and include a public review for standards which follow the ANSI standard approval process. In developing these standards, purposeful thought is provided on which obligations should be recommended and which required. Recommended obligations are those that are best in practice for specific situations, but that may not be appropriate to require broadly. If members of these organizations now know that it is PHMSA’s desire to mandate all “should” statements, AGA is concerned that consensus organizations will significantly reduce recommended statements in their standards, thus defeating the goal of having future meaningful consensus standards for the industry.

By incorporating by reference “recommendations,” PHMSA is ignoring the intent and context of these consensus standards. PHMSA has failed to provide any justification or explanation to support the inclusion of these recommendations. AGA encourages PHMSA to revise its proposal to eliminate incorporating “recommendations” as regulatory requirements.

API “In-Line Inspection Systems Qualification Standard,”


In addition, AGA points out that the API standard covers in detail aspects of ILI inspections, most of which are not covered by Part 192, including aspects that PHMSA has stated are not covered by this Proposed Rule, including Quality Management of Change. See 81 Fed. Reg. 20735 which notes that PHMSA will consider Quality Management of Change in a separate rulemaking. Also, each standard is similar but not the same. Differences in language, intent and structure of multiple standards on the same topic (e.g., ANSI STD 1163, ANSI/ASNT ILI-PQ-2005 and NACE SP0102-2010) will lead to regulatory uncertainty if all are incorporated by reference without careful consideration on their overlapping areas. AGA encourages PHMSA to review this incorporation by reference, as well as the other documents proposed to be incorporated, to ensure the standards to be incorporated are not in conflict with Part 192.

AGA’s proposed changes to sections 192.7, 192.150, and 192.493 that reference IBRs are shown below. AGA’s proposed changes to § 192.927 and § 192.929 can be found in the applicable topic specific section comments:

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


§192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices, in accordance with the requirements and recommendations in NACE SP0102-2010, Section 7 (incorporated by reference, see §192.7)

§ 192.493 In-line inspection of pipelines

When conducting in-line inspection of pipelines required by this part, each operator must comply with the requirements and recommendations of API STD 1163, In-line Inspection Systems Qualification Standard, except for Section 11, Quality Management System; ANSI/ASNT ILI-PQ-2005, In-line Inspection Personnel Qualification and Certification; and NACE SP0102-2010, In-line Inspection of Pipelines (incorporated by reference, see §192.7). Assessments may also be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102-2010, provided they comply with those sections of NACE SP0102-2010 that are applicable.

V. PRELIMINARY REGULATORY IMPACT ASSESSMENT

Throughout these comments AGA has provided topic specific examples of where PHMSA has either neglected to account for the regulatory impact of elements within the Proposed Rule or has inadequately accounted for the scope, cost, or benefit of the proposed regulatory changes. The following comments provide additional discussion on PHMSA’s Preliminary Regulatory Impact Assessment (PRIA), organized by PHMSA’s chosen topic areas, within the PRIA:

1. Re-establish MAOP, Verification of Material Properties, and Integrity Assessment and Remediation for Segments Outside HCAs
2. IMP Process Clarifications
3. Management of Change
4. Corrosion Control
5. Inspection of Pipelines Following Extreme Weather Events
6. MAOP Exceedance Reports and Records Verification
7. Launcher/Receiver Pressure Relief
8. Expansion of Regulated Gas Gathering Pipelines

Following AGA’s topic-specific PRIA comments, AGA will address concerns with PHMSA’s reliance on the social cost of methane in this impact assessment. As the following details will support, AGA believes the PRIA for this proposed rule does not adequately represent the costs expected to be incurred by operators and ultimately the customers they serve, all for little to no pipeline safety improvements.

AGA urges PHMSA to provide a regulatory impact assessment with the final rule that address each individual code section as organized in the preamble to evaluate the costs and benefits directly associated with those changes. Organizing the PRIA by the topic areas as PHMSA has done, provides for a convoluted assessment document in which it is extremely difficult, if not impossible, to evaluate or follow PHMSA’s attempt to assess regulatory impacts of the Proposed Rule.
(1) **Topic Area 1: Re-Establish MAOP, Verification of Material Properties, and Integrity Assessment and Remediation for Segments Outside HCAs.**

While AGA appreciates PHMSA’s attempt to breakdown this enormous rule into manageable sections for the purposes of the impact analysis, AGA questions why PHMSA has chosen to incorporate nearly all of the substantive and impactful proposed requirements into the first topic area. PHMSA has blended four of the major proposed changes within the Proposed Rule in this single topic area: MAOP Verification (§192.624), Material Verification (§192.607), Pipeline Assessments Outside HCAs (§192.710), and modified Repair Criteria (§192.713 and §192.933). Through this effort, PHMSA has made it incredibly difficult for even the most informed reader to understand how the impacts have been determined or calculated, what pipelines PHMSA has assumed are subject to the various requirements, and where the cost assumptions originate.

AGA has significant concerns with PHMSA’s estimated cost and justification for the MAOP Verification requirements. Through the mandate in Section 23 of the Act, Congress provided PHMSA with explicit instructions to consider costs and to provide efficient and feasible regulations for MAOP Verification. Specifically, for those pipelines where records are insufficient to confirm the established MAOP, the regulations must be “economically feasible.” See 49 U.S.C. §60139(c)(1)(A). Similarly, for those untested pipelines, PHMSA must “minimize costs and service disruptions.” Id. at §60139(d)(3). For those pipelines outside of the Section 23 mandate, PHMSA’s authority is limited by the restrictions on its general authority, including the requirements to consider the costs and benefits that any standard must be based on a reasoned determination that the benefits of the intended standard justify its costs, and the restrictions on PHMSA’s authority to promulgate certain retroactive requirements on existing pipelines. Id. at §60102(b).

AGA has identified many errors and inconsistencies in PHMSA’s PRIA methodology and assumptions, and has found that many of PHMSA’s cost estimates in the PRIA severely underestimate actual costs experienced by operators. The significant and widespread inaccuracies result in a PRIA that clearly fails to meet the requirements of the Congressional mandates in Section 23 and exceeds PHMSA’s general authority.

As noted above, PHMSA’s organization of its impact assessment for MAOP Verification makes it extremely difficult, if not impossible, for stakeholders to review and make meaningful comment on the PRIA. PHMSA has broken down the impacts of the proposed MAOP Verification requirements in a manner that is inconsistent with and differs in scope from the way the proposed regulatory text is discussed. For example, although the proposed MAOP Verification requirements make no distinction between transmission pipelines operated above 30% SMYS and those operated at less than or equal to 30% SMYS, PHMSA has chosen to break out its regulatory impact assessment in this manner. See PRIA, pages 33, 57. The Table V-1 displays how PHMSA has categorized pipelines subject to the proposed MAOP Verification requirements. Column (1) displays information from the Proposed Rule, and column (2) displays information from the PRIA.

<table>
<thead>
<tr>
<th>Table V-1. Comparison of Scope of Proposed MAOP Verification (§192.624(a)) with PRIA Estimates</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipelines With Manufacturing- and Construction-Related Defects Resulting in Reportable Incidents</td>
</tr>
<tr>
<td>Proposed Regulatory Text (§192.624(a)(1))</td>
</tr>
</tbody>
</table>

203
• High consequence areas
• Class 3 and class 4 locations
• Moderate Consequence Area that can be inspected by ILI

• No estimate

Breaking out the assessment in this manner requires PHMSA to make additional estimates of the mileage of pipelines operating at different pressure levels. See, e.g., PRIA Table 3-2 at 34. As a result, it provides for a confusing comparison that is difficult for the reviewer to evaluate the potential impact. Of greater concern, it has resulted in PHMSA not including in the PRIA categories of pipelines that would be subject to the proposed MAOP Verification requirements.

Specifically, PHMSA has failed to account for the impact on previously untested pipelines in HCAs that operate at 20% SMYS or less (proposed §192.624(a)(3)(ii)) and the impact on pipelines with manufacturing- and construction-related defects that result in a reportable in-service incident (proposed §192.624(a)(1)). Neither of these categories of pipelines fall within the Section 23 Congressional mandate. PHMSA’s authority is thus limited by its general authority, which obligates PHMSA to consider the estimated costs and benefits associated with applying the standard to these pipelines.

AGA fundamentally disagrees with many of PHMSA’s assumptions, cost estimates, and analytical approaches underlying its estimate of the impact of the proposed MAOP Verification requirements and Assessments Outside HCAs. Below, AGA provides comments on the following:

(A) Unit Costs of Assessments for MAOP Verification and Assessments Outside of HCAs
(B) Estimates of Impacted Mileage for MAOP Verification
(C) Breakdown of Assessment Methods Used for MAOP Verification
(D) Breakdown of Assessment Methods Used for Integrity Management Outside HCAs
(E) PHMSA’s Failure to Account for Costs of Material Verification
(A) Unit Cost of Assessments for MAOP Verification and Assessments outside of HCAs

In order to better understand the cost inaccuracies that permeate Topic Area #1 – Re-establish MAOP, Verification of Material Properties, and Integrity Assessment and Remediation for Segments Outside HCAs – AGA would first like to outline the flaws in PHMSA’s estimate of the cost to perform each of the three “primary” assessment techniques or methodologies for MAOP Verification - upgrading to perform in-line inspection, running in-line inspection, and pressure testing – as well as PHMSA’s estimated cost of direct assessments for use in Integrity Management Outside of HCAs.

Upgrade to ILI

First, in the cost estimates associated with “Upgrade to ILI”, PHMSA acknowledges that there are costs associated with the value of gas lost during the pipeline upgrades necessary to accommodate the passage of an ILI tool and for an inspection-related blowdown. However, PHMSA makes an incorrect assumption in Equation 1 that the operating pressure levels in all intrastate pipelines are capable of being reduced to 100 psig and all interstate pipelines may be reduced to 150 psig. For AGA member company pipelines, this is not operationally feasible. Intrastate transmission pipelines typically do not have excess capacity, and a reduction in operating pressure to this level (100 psig) would significantly impact the operator’s ability to provide safe and reliable service to customers and communities that they serve. This incorrect assumption causes the PRIA to significantly underestimate the amount of lost gas in each of PHMSA’s examples in Table 3-6. Also, the footnote #4 in Table 3-6 states the assumed blowdown condition is 50 psi, which is even less than stated 100-150 psi in 3.1.4.3 and is even more unrealistic of actual conditions that will be experienced.

AGA has significant concerns with PHMSA’s estimate of the cost to upgrade a transmission pipeline to accommodate the passage of ILI tools and its dismissal of costs that are based on actual experience. Specifically, PHMSA has publically available information provided by Southern California Gas Company and San Diego Gas & Electric Company (SoCalGas) on the cost for upgrading a transmission pipeline to accommodate the passage of ILI tools ($4.4 Million - $4.7 Million). These costs are based on actual experience, are not included in the PRIA, and AGA strongly opposes their complete dismissal by PHMSA. PHMSA appears to have accepted Pacific Gas & Electric’s (PG&E) estimate of the company’s cost to upgrade its transmission pipeline to accommodate the passage of ILI, and we are hopefully that these costs were not included only because they conveniently fell within the range of PHMSA calculated costs in Table 3-7. PHMSA cannot dismiss the SoCalGas estimate, which is based on actual experience, simply because it was significantly higher and thus did not support the change PHMSA sought to make in the regulations. It is AGA’s observation that PHMSA has preferentially selected facts that indicate lower costs for its proposed regulation and ignored facts that indicate higher costs or do not support PHMSA’s assumptions. AGA believes that SoCalGas’s operating conditions do not “represent site-specific conditions that are not representative of the costs elsewhere and over a wide range of pipeline facilities,” but instead represent conditions that many operators in urban areas would reasonably expect to experience. PG&E’s HCA mileage represents 18% of their overall pipeline mileage, while the SoCalGas HCA mileage represents 35%99 of their transmission system. AGA would argue that SoCal’s cost estimates represent a very important sampling of intrastate transmission pipelines that are in HCAs and should not be dismissed simply because they are significantly greater than PHMSA’s “Best Professional Judgment” (BPJ) that as conveyed in the PRIA. This dismissal lacks reason, technical justification and skews the PRIA.

Similarly, PHMSA chose to ignore INGAA’s estimate of $1 Million per mile because “the high end is considerably higher”. PHMSA attempts to justify this exclusion by stating that “information is not available about the components and wide applicability of the costs, or is insufficient.” Again, it appears that PHMSA is preferentially selecting only the information that support its cost assumptions and ignoring that which would make their cost-benefit analysis less acceptable. Not having additional detailed information about component costs, or applicability, is hardly a reason to completely dismiss data that is available and is based on actual operator experience in the field. It appears PHMSA is accepting cost estimates that support its own estimates, but dismissing all those that are greater than the range estimated by PHMSA in an effort to make this and other proposed regulatory changes cost beneficial.

Additionally, PHMSA makes unreasonable assumptions that seriously underestimate the number of mainline valves that would need to be replaced for intrastate pipelines that are not already capable of inspection by ILI tools and the costs for the purchase and installation of those replacement valves, bends, launchers and receivers. In Table 3-7 of the PRIA for pipelines in Class 3, Class 4 and HCA locations, PHMSA estimated that an 8” intrastate pipeline of 15 miles will have two valves and six bends that need replacement. At $89,000 per valve and $16,000 per bend, PHMSA estimates a cost of $17,200 per mile for replacement of valves and bends. An AGA member that operates an in urban area reported this cost to be closer to $1,500,000 per mile for the replacement of valves and bends, a difference of $1,482,800. Although this is just one data point, it displays the severity of these unfounded, unsupported assumptions. PHMSA has seriously underestimated the regulatory impact.

Furthermore, by performing a weighted average cost per mile on the estimates calculated in Tables 3-6 and 3-7, PHMSA ultimately calculates a cost between $31,930 and $44,972 for interstate pipelines and $40,512 and $86,176 for intrastate pipelines. Both of these ranges fall significantly below the estimates provided by PG&E and SoCalGas for intrastate pipelines that are based on recent, actual operator experience, and are far below INGAA’s estimate of cost per mile for interstate pipelines.

PHMSA specifically acknowledges the challenges it experienced in estimating costs associated with many of its proposed changes by stating “…PHMSA lacked direct data or evidence on the values or parameters used in the analysis… [PHMSA] relied on its experts’ best professional judgement of the likely values.” PHMSA has a regulatory obligation to provide reasonable estimates of cost in its impact analysis and to provide data that support its BPJ assertions. PHMSA provides neither in its PRIA. PHMSA cannot simply defer its regulatory obligation by making unfounded and unjustified assumptions claiming “best professional judgment” and then request comment from industry that “are supported by accompanying data”. PHMSA has a legislative and regulatory obligation to provide detailed information to support its assumptions, just as PHMSA requires of operators when an operator makes a sound engineering assumption. AGA highly recommends that PHMSA make additional efforts to acquire actual data available from operators when preparing the final rule and future proposed rules so that future PRIAs truly reflect valid cost estimates to implement the rule.

**In-Line Inspection**

In the first sentence of this section, PHMSA states their assumption that “an operator would run three ILI tools per assessment conducted with its proposal for ILI assessments performed to re-establish MAOP in
accordance with §192.624.” AGA addresses this assumption in Section IV.A.3 of these comments, but is concerned that PHMSA has inadequately accounted for the costs associated with doing a complete Engineering Critical Assessment per the requirements in the Proposed Rule, including: analysis of material and operational documents, metal loss defects, and predicted failure pressures.

In Table 3-9 of the PRIA, PHMSA outlines six different scenarios to help estimate the total costs to run three ILI tools: base MFL, and a combination tool for deformation and cracks. AGA asked its members to estimate the costs associated with running ILI tools, including the elements within Table 3-9: mobilization, base MFL tool, additional combo tool, reruns, analytical and data integration, and operator preparation. Table V-2 below offers a side by side comparison of PHMSA’s BPJ and the average cost reported by 40 AGA operators.

<table>
<thead>
<tr>
<th>Intrastate (30-mile)</th>
<th>PHMSA Total BPJ</th>
<th>AGA Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>26” – 48”</td>
<td>$178,750</td>
<td>$476,296</td>
</tr>
<tr>
<td>14” – 24”</td>
<td>$150,150</td>
<td>$498,352</td>
</tr>
<tr>
<td>4” – 12”</td>
<td>$121,550</td>
<td>$370,143</td>
</tr>
</tbody>
</table>

AGA highlights the fact that PHMSA’s BPJ costs are only 30% – 38% of actual industry experienced costs associated with in-line inspection. It is critical to note this significant understatement of costs associated with the conducting ILI inspections as this underestimation carries throughout PHMSA’s PRIA.

Another important error noted in the PRIA is PHMSA’s assumption that the average intrastate ILI segment is 30 miles long. This exemplifies PHMSA’s misconception of intrastate transmission pipelines. AGA members report that their average ILI segment is between 3 and 15 miles long, not 30 miles. This revision would greatly impact PHMSA’s calculated unit cost of performing an ILI inspection, as only 22% of the total cost for performing ILI inspection is on a per-mile basis.

As mentioned previously, all of the identified incorrect assumptions and understated costs are exaggerated by PHMSA’s decision to use weighted average costs per mile to allocate costs to the execution of each assessment method. PHMSA concludes in Table 3-10 that the average cost per mile for an interstate 60-mile segment is $4,324 and $4,594 for a 30-mile intrastate pipeline. This starkly contrasts with the weighted average of AGA’s data of $15,594 per mile. This clearly indicates that additional efforts need to be made by PHMSA to better estimate the actual costs of implementing the rule as proposed. Incorrect estimates in this order of magnitude will result in significantly increased costs and drastically reduced benefits to the public than were proposed by PHMSA, and cannot satisfy PHMSA’s statutory mandate to ensure that the costs of the rule are justified.

**Pressure Testing**

To estimate the cost of pressure testing, PHMSA relied on vendor pricing from a single data source. The 40 AGA members that provided estimates for conducting hydrostatic pressure tests, including all of the activities listed within Table 3-11 and its notations, reported significantly higher cost data compared to PHMSA’s data and

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101 The Greene’s Energy Group, LLC estimate was not provided for public review within the regulatory docket. As a result, the ability to provide meaningful substantive comment is limited.
assumptions. It should be noted that this actual cost data from operators does not include the cost to provide alternative gas supplies in scenarios where temporary gas is necessary to maintain safe and reliable service to customers. PHMSA has estimated that 10% of all pressure test scenarios require temporary gas to supply customers at a cost of $1 million per test. AGA members with experience in providing temporary gas supply reported an average cost of $495,354 per mile to provide gas service during a pressure test. For AGA members, the length of the transmission pipeline being pressure tested impacts the cost to provide temporary gas supply, since for many intrastate gas transmission pipelines there could be multiple customers directly connected to the pressure test segment. Pressure testing an existing in-service transmission pipeline is much more complicated than just transporting the gas supply across the segment.

Even if one combines PHMSA’s assumptions of the pressure test costs, including temporary gas supplies and lost gas considerations, PHMSA’s estimates remain significantly lower than the actual costs that have been identified by AGA members through their experiences. AGA members reported significantly higher costs than PHMSA’s totals in Table 3-18 for intrastate pipelines. Table V-3 below shows the variances between the pricing data used by PHMSA and actual operator costs:

Table V-3: PHMSA’s Presumed Unit Costs per mile for Pressure Testing vs. AGA Member Data

<table>
<thead>
<tr>
<th>Pipe Diameter (inches)</th>
<th>Segment Length (miles)</th>
<th>1</th>
<th>2</th>
<th>5</th>
<th>10</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PHMSA</td>
<td>AGA</td>
<td>PHMSA</td>
<td>AGA</td>
<td>PHMSA</td>
</tr>
<tr>
<td>12</td>
<td>$374,146</td>
<td>$501,672</td>
<td>$189,926</td>
<td>$433,859</td>
<td>$87,073</td>
</tr>
<tr>
<td>24</td>
<td>$446,406</td>
<td>$846,421</td>
<td>$230,918</td>
<td>$621,229</td>
<td>$141,152</td>
</tr>
<tr>
<td>36</td>
<td>$634,837</td>
<td>$1,137,643</td>
<td>$368,598</td>
<td>$954,229</td>
<td>$191,942</td>
</tr>
</tbody>
</table>

PHMSA performed a weighted average calculation to determine the unit pressure test assessment cost per mile, which results in a cost of $203,556 per mile for pressure testing. This estimated cost is less than all but one scenario, a 10-mile, 12” segment, reported by AGA membership. This cost data point alone should underscore the inaccuracies and significant understatement of PHMSA’s estimate. When AGA performs this same weighted average unit cost calculation per mile, AGA concludes the average unit cost for pressure testing is $441,410. This also clearly indicates that additional efforts should be made by PHMSA to better estimate the actual costs of implementing the rule as proposed. Incorrect estimates in this order of magnitude will result in significantly increased costs and drastically reduced benefits to the public than were proposed by PHMSA. PHMSA cannot rely on inaccurate costs of this nature to support its Proposed Rule.

Direct Assessment

In section 3.1.4.5 of the PRIA, PHMSA estimates the unit cost of direct assessment (DA). PHMSA includes no real world data and simply uses its BPJ on the costs for the four phases of DA, providing a low, mid, and high estimate for the direct assessment method. While PHMSA’s BPJ is relatively accurate for the pre-assessment and post-assessment phases, based on a comparison to AGA’s industry survey data, PHMSA has significantly underestimated the cost to perform direct examination. AGA members provided detailed costs for each of these phases and Table V-4 provides a side-by-side comparison of PHMSA’s mid-estimate and AGA membership’s average costs which are based on actual operator experience.

Table V-4: Side-by-Side Comparison of DA Cost per Mile
<table>
<thead>
<tr>
<th>Phase</th>
<th>PHMSA Mid-Estimate</th>
<th>AGA Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-Assessment</td>
<td>$7,500</td>
<td>$5,360</td>
</tr>
<tr>
<td>Indirect Examination</td>
<td>$10,250</td>
<td>$22,711</td>
</tr>
<tr>
<td>Direct Examination</td>
<td>$17,500</td>
<td>$84,434</td>
</tr>
<tr>
<td>Post-Assessment</td>
<td>$7,500</td>
<td>$6,711</td>
</tr>
<tr>
<td>Total</td>
<td>$42,750</td>
<td>$119,276</td>
</tr>
</tbody>
</table>

Based on a review of the table above, which summarizes the Direct Assessment costs estimated by PHMSA compared to the actual costs reported by operators, it is readily apparent that the PRIA dramatically understates the cost to perform a DA assessment. The PHMSA estimate is less than 36% of the actual costs reported by operators. This is another example that clearly indicates that additional efforts should be made by PHMSA to better estimate the actual costs of implementing the rule as proposed. Incorrect estimates in this order of magnitude will result in significantly increased costs and drastically reduced benefits to the public than were proposed by PHMSA. PHMSA cannot rely on inaccurate costs of this nature to support its Proposed Rule.

(B) **Estimation of Mileage for MAOP Verification**

AGA is concerned with PHMSA’s estimation of mileage that falls within the proposed MAOP Verification requirements, and its lack of inclusion of certain pipelines that will be subject to MAOP Verification. This lack of inclusion of pipelines that will be subject to MAOP Verification provides another indication that the costs of the proposed regulation are inadequately accounted for in the PRIA. Below are specific areas where the PRIA inadequately accounts for MAOP Verification costs:

- **Pipelines With Manufacturing- and Construction-Related Defects Resulting in Reportable Incidents (§192.624(a)(1))**: PHMSA has not provided an estimate of the number of miles that would be subject to §192.624(a)(1), either based on past incidents or based on PHMSA’s estimate of the miles that could potentially have an incident in the future. AGA reminds PHMSA that this category of pipelines is outside of the Congressional mandate and that PHMSA is bound by the limitations placed on its general authority in regulating these pipelines, including that the proposal be reasonable, feasible, practical and cost beneficial.

- **Pipelines With Inadequate Pressure Test Records (§192.624(a)(2))**: PHMSA provides an estimate of the mileage of pipe for which records are inadequate in Table 3-26. According to PHMSA, the source of this information is the PHMSA 2014 Gas Transmission Annual Report: Part Q Sum of “Incomplete Records” column. From AGA’s review of the 2014 Annual Report data, it appears that PHMSA’s estimate is based on mileage associated with “incomplete records” for Design Pressure (§192.619(a)(1)), Pressure Test (§192.619(a)(2)), Highest Operating Pressure (§192.619(a)(3)), Engineering Considerations (§192.619(a)(4)), and the Grandfather Clause (§192.619(c)). By including each of these MAOP Determination methods, PHMSA’s mileage estimate in the PRIA captures mileage greater than would be captured by the regulatory text alone, which is limited to pipelines that do not have a valid “subpart J” pressure test. To be consistent with the regulatory text, PHMSA should only include mileage associated with incomplete records for Pressure Test, §192.619(a)(2). However, AGA notes that even this mileage would not represent the total mileage captured by the proposed regulatory text in §192.624(a)(2) because it does not capture situations
where a pipeline had complete records for Design Pressure (§192.619(a)(1)), but did not have a pressure test record (§192.619(a)(2)).

- **Pipelines in HCAs Operating at Less Than 20% SMYS and Relying on §192.619(c) (§192.624(a)(3))**: PHMSA has not included mileage of pipelines in HCAs relying on the grandfather clause and operating below 20% SMYS. These pipelines would be impacted by the Proposed Rule under §192.624(a)(3). AGA reminds PHMSA that these pipelines are outside of the Congressional mandate and that PHMSA is bound by the limitations placed on its general authority in regulating these pipelines, including that the proposal be reasonable, feasible, practical and cost beneficial.

(C) **Breakdown of Assessment Methods Used for MAOP Verification**

AGA disagrees with PHMSA’s expectation that most operators will use ILI in conjunction with engineering critical assessment or pressure testing to verify MAOP. See PRIA, pages 33, 49, 60. The Table V-5 summarizes the MAOP Verification method that 40 AGA member companies representing 13,600 miles of pipeline subject to the proposed MAOP Verification requirements would expect to use.

<table>
<thead>
<tr>
<th>Table V-5: MAOP Verification Method Distribution for AGA Membership</th>
</tr>
</thead>
<tbody>
<tr>
<td>% of 192.624 applicable pipelines that would have the ABILITY to use each assessment method* (average)</td>
</tr>
<tr>
<td>Pressure Test</td>
</tr>
<tr>
<td>Pressure Reduction</td>
</tr>
<tr>
<td>ECA (with an ILI)</td>
</tr>
<tr>
<td>Replacement</td>
</tr>
<tr>
<td>Pressure Reduction by 10% for Small PIR and Diameter 8-inch or lower</td>
</tr>
<tr>
<td>Alternative Technology</td>
</tr>
</tbody>
</table>

*WILL NOT ADD UP TO 100%

As discussed in detail above, due to the prescriptive and onerous requirements associated with Engineering Critical Assessment (ECA), this method for MAOP Verification is not a viable option for most operators. In fact, due to the significant concerns regarding the practicality of all of the MAOP Verification methods proposed in §192.624(c), pipe replacement would be the MAOP Verification method that is most usable by operators

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102 Under PHMSA’s file structure for the DOT report, the mileage summary column has to equal the total mileage of the pipeline, so that if records report pipeline mileage as sufficient to document MAOP in one category (for example design calculation), they cannot also report the same mileage as having insufficient records in another category (for example pressure test). Since the report is structured to capture the quality of records for which the MAOP is actually based on, numbers reported in the insufficient record categories are severely under represented and are not a valid basis for PHMSA’s mileage estimate for pipelines with insufficient pressure test records.
surveyed (36.8%), with pressure testing as the second most viable option (26.1%). Pipeline replacement should be the last resort for MAOP Verification and should be required only when other MAOP Verification methods are operationally impractical or fail to be cost effective. It is also important to recognize that pressure testing of in-service transmission pipelines presents a significant operational challenge for most AGA members. Pipe replacements will also result in drastic increases to the actual cost of implementing the Proposed Rule that are not accounted for in the PRIA.

PHMSA bases its position that most operators will perform in-line inspections in conjunction with ECA or will pressure test to verify MAOP on various data from annual reports as well as PHMSA’s “best professional judgment.” In general, PHMSA believes that operators will ILI all transmission pipelines capable of accommodating an ILI tool, will pressure test the same percentage of lines previously tested based upon history, and will update the remaining lines to be ILI capable. By making these broad assumptions, PHMSA fails to consider the unique challenges associated with MAOP Verification on the transmission pipelines subject to §192.624, especially intrastate transmission pipelines, and the prescriptive and onerous nature of the proposed MAOP Verification methods that make them more challenging to perform than traditional assessment methods.

In addition, PHMSA fails to account for any cost or distinction between performing an ILI integrity assessment on a transmission pipeline and performing the ILI/ECA MAOP Verification method on a pipeline. As noted above, the prescriptive and onerous requirements of the ECA will prohibit most operators from selecting this option for MAOP Verification. Nowhere in the PRIA does PHMSA estimate or take into account the cost of the ECA. As a result, PHMSA’s assumption that if a pipeline is ILI capable, then an operator will choose the ILI/ECA option is incorrect. In addition, PHMSA applies the percentage of pipelines that are ILI-capable generally to the smaller subset of pipelines that would be subject to the MAOP Verification requirements.

PHMSA’s assumptions ignore the distinctions between pressure testing as an integrity management assessment method and the MAOP Verification requirements, which, for “legacy pipe”, “legacy construction techniques” or incidents related to manufacturing or construction defects, will require the performance of a hydrostatic spike pressure test. Performing a hydrostatic spike pressure test on pipelines currently in service presents additional challenges not present when gas is used to conduct a pressure test. For example, the feasibility of obtaining sufficient water and disposing of the water in accordance with environmental regulatory restrictions, and the logistics of removing the gas from the line, cleaning the line, filling the line with water, conducting the hydrostatic pressure test, and then removing all the water from the line, and drying the line to prevent future internal corrosion issues are not included in the consideration of whether to perform a pressure test using gas versus water. Furthermore, there are regulatory options and requirements that an operator must consider when choosing an assessment method for integrity management purposes that are significantly different than what PHMSA is proposing for MAOP Verification. For example, direct assessment is an option for integrity management assessments but not MAOP Verification. Based on these differences, simply because an operator relied upon pressure testing as an integrity management method on a certain percentage of pipelines in the past does not mean that the operator will use pressure testing for MAOP Verification at the same frequency.

It should also be noted that there are unique challenges associated with pipelines subject to the proposed MAOP Verification requirements that make them less likely to be capable of accommodating inspection by an ILI tool. For example, these pipelines are generally older (evidenced by their reliance on the “grandfather” clause to determine the MAOP) and were not designed to accommodate the passage of ILI tools. AGA reminds PHMSA that
the provision to design and construct new and replacement sections of transmission pipelines to accommodate the passage of ILI devices was not a requirement in Part 192 (§192.150) until 1994 (this requirement was further amended in 1998 and 2004). Upgrading these pipelines to accommodate inspection by ILI tools is especially challenging and problematic. In fact, for HCAs, given that these lines have already been subject to Subpart O requirements that could be satisfied through the use of ILI technology, there is a strong likelihood that upgrading to be capable of accommodating an ILI tool is not feasible, reasonable or cost-effective if the pipelines have not already been upgraded to be ILI capable.

AGA questions PHMSA’s use of best professional judgment in its final estimates of the frequencies of methods that will be used for MAOP Verification. See PRIA Table 3-5. PHMSA relies on historic values for pressure testing and appears to apply them unreasonably to different classes of pipelines. PHMSA’s data indicates that for interstate pipelines, 5% of assessments per year were conducted using pressure tests. PHMSA applies this 5% value to transmission lines in Class 1, Class 2 and Class 3 locations, and then PHMSA assumes that the remaining pipelines that are not yet ILI capable will be retrofitted to accommodate ILI tools. However, for Class 4 pipelines, PHMSA assumes none will be pressure tested, and that all pipelines that are not yet ILI capable will be retrofitted for ILI tools. First, there is no support or justification for PHMSA’s applications of these percentages, or a justification for why Class 4 pipelines were treated differently from Class 1, 2 and 3 pipelines. Second, it is unclear why PHMSA believes that these pipelines are even capable of being updated to accommodate ILI tools.

The estimates for intrastate pipelines are even more unrealistic. PHMSA’s data suggests that 10% of intrastate transmission pipeline assessments are performed using pressure tests. PHMSA assumes this rate will remain constant for Class 1 pipelines, but for Class 2 and Class 3 pipelines, PHMSA estimates 20% and for Class 4 pipelines, PHMSA estimates that operators will use pressure testing for 21% of the pipelines. PHMSA provides no description, justification or support for establishing these estimates.

As noted above, although PHMSA has proposed six methods for MAOP Verification in §192.624(c), PHMSA has only estimated a portion of costs for two methods: pressure testing and the ILI portion of the ILI/ECA method. PHMSA has failed to provide any cost estimate for pressure reductions, either generally or for small diameter pipe, pipe replacement, or alternative technology. As noted above, based on an AGA survey of 40 members, there is a clear recognition that many of the methods, if not all of the methods, will be utilized. In fact, PHMSA’s statement that it does not expect operators to rely on these other methods is inconsistent with PHMSA’s proposal of these methods, and supports that they are in fact not reasonable. PHMSA authority is limited to prescribing reasonable standards that are based on a reasoned justification that the intended benefits justify the costs. By suggesting that operators will not rely on these other measures because they are “extreme measures, and more costly,” see PRIA at page 33, by PHMSA’s own admission the proposed MAOP Verification requirements are inconsistent with PHMSA’s general authority and are not reasonable, feasible, practical or cost beneficial. Furthermore, PHMSA’s statements in the PRIA regarding these additional methods are contrary to PHMSA’s statements in the preamble, describing the ECA and the pressure reduction for small pipelines, and the flexibility purported to be provided by the Proposed Rule. See 81 Fed. Reg. 20813-14.

For pipelines that have insufficient records to confirm the established MAOP, PHMSA’s proposed MAOP Verification requirements cannot be said to address these pipelines as “expeditiously as economically feasible.” See 49 U.S.C. §60139(c)(1)(A). By failing to provide cost estimates associated with the majority of the MAOP Verification methods that will be used by operators, there is no evidence that PHMSA took the Congressional
mandate into consideration. Similarly, by failing to provide cost estimates for previously untested pipelines in HCAs operating at greater than 30% SMYS, there is no indication that PHMSA’s proposal has complied with the Congressional mandate to “minimize costs.” Id. at §60139(d)(3). Lastly, for pipelines outside of the Section 23 mandates, PHMSA’s failure to consider these costs is in direct contradiction of PHMSA’s limited authority to prescribe regulations based on an estimate of the costs. Id. at 60102(b).

Because applicability within the MAOP Verification section is in part predicated on the requirement to have a pressure test record (§192.624(a)(2)), operators are in essence forced to use the pressure test as a verification method, to the exclusion of the other methods. If a pipeline operator chooses any of the other five methodologies within §192.624(c) besides Method 1: Pressure test, the identified pipeline will continue to meet the applicability requirements of §192.624(a)(2) for not having a record of a completed pressure test. Eliminating this flexibility is in direct violation of the Section 23 Congressional mandates. For pipelines with insufficient records to confirm MAOP, limiting MAOP Verification to pressure testing eliminates other effective and less costly measures that can be implemented in a timelier manner. This is also in direct violation of the Congressional mandate that PHMSA require the MAOPs for these pipelines be reconfirmed as “expeditiously as economically feasible.” See 49 U.S.C. §60139(c)(1)(A).

As discussed in AGA’s comments on MAOP Verification, pipelines that rely on the “grandfather clause” in §192.619(c) and meet the applicability of §192.624(a)(3) will most likely also meet the applicability of §192.624(a)(2) for not having “pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment”. For these pipelines, if a pipeline operator chooses any of the five other methodologies within of §192.624(c) besides Method 1: Pressure test, the pipeline in question will continue to meet the applicability requirements of §192.624(a)(2) for not having a pressure test record. In practical terms, this results in all “grandfathered pipelines” subject to §192.624(a)(3) being forced to perform a pressure test.

Requiring all “grandfathered pipelines” to rely upon the pressure test method for MAOP Verification is contrary to the Congressional mandate and inconsistent with PHMSA’s own PRIA. Congress specifically instructed PHMSA to consider the use of ILI technology and other alternative technologies determined to be of equal or greater effectiveness as pressure testing. See 49 U.S.C. §60139(d)(3). PHMSA has even determined that the methodologies proposed in lieu of pressure testing “would provide equal or greater effectiveness as a pressure test.” See 81 Fed. Reg. 20813. By eliminating these methods as compliance options, PHMSA’s Proposed Rule is inconsistent with and contrary to Congress’ clear mandates in Section 23.

The fact that transmission pipeline operators will be forced to rely on the pressure test method also is inconsistent with the PRIA, which assumes that 5% of interstate pipelines and 10-20% of intrastate pipelines will be pressure tested.103 The pipelines described in Sections 3.1.4, 3.1.5, and 3.1.7 would all need to be pressure tested, and none would perform the MAOP Verifications by use of in-line inspection or any of the other methodologies.

This greatly alters the overall estimated cost impact of the Proposed Rule. Additionally, PHMSA’s underestimated costs for ILI and Pressure Testing demonstrate the extremely high cost difference between the two methodologies. Thus, the estimated costs in the PRIA were extremely underestimated. See Table V-6.

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103 See Table 3-20, Table 3-29, Table 3-41.
Table V-6: Unit Cost Differential between ILI and Pressure Test per Mile using PHMSA BPJ

<table>
<thead>
<tr>
<th>Segment Type</th>
<th>ILI</th>
<th>Pressure Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interstate</td>
<td>$4,324</td>
<td>$226,939</td>
</tr>
<tr>
<td>Intrastate</td>
<td>$4,594</td>
<td>$203,556</td>
</tr>
</tbody>
</table>

(D) The Breakdown of Assessment Methods used for Assessments Outside of HCAs

This portion of the PRIA is directly linked with the new requirements within proposed section §192.710, which requires operators to perform assessments on pipelines in non-HCA Class 3 locations, Class 4 locations, and MCAs that are able to accommodate inspection by means of an instrumented in-line inspection tool. A fundamental principle in the impact analysis of this new requirement is that operators have already gone above and beyond current regulatory requirements to assess pipelines outside HCAs. PHMSA asserts that by allowing operators to utilize these past assessments to achieve regulatory compliance, the cost for operators to perform these assessments can be removed from the impact assessment.

As discussed in Section IV.B of these comments on MCAs, AGA is deeply concerned that PHMSA states that they “do not have data on the pipeline mileage that would meet the MCA definition.” AGA believes this lack of information and understanding of the impact of their proposed regulatory changes underscores PHMSA’s significantly understated impact assessment. Applying random percentages to the non-HCA pipelines to define those pipelines that would be located in MCAs, without providing supporting information, is completely arbitrary, capricious, and without technical justification.

Additionally, in section 3.1.6.2 of the PRIA, PHMSA attempts to quantify the number of non-HCA pipelines that have received an integrity assessment by utilizing PHMSA Gas Transmission Annual Report information as noted in Note 5 in Table 3-33. PHMSA assumed that 90% of non-HCA pipe in Class 4 locations has been assessed during Subpart O integrity assessments, 80% in Class 3 locations, 70% in Class 2 locations, and 50% in Class 1 locations. AGA attempted to verify these estimates and concluded that the likely methodology used by PHMSA is invalid and results in incorrect conclusions. Based off Note 5 in Table 3-33, which says “assumed based on the overall reported assessed mileage and assessed mileage in HCAs”, AGA assumes that PHMSA utilized information from its annual report, specifically Part F. Integrity Inspections Conducted and Actions Taken Based on Inspection, Question F.6.a “Total mileage inspected in calendar year” and Part G Miles of Baseline and Reassessments Completed in Calendar Year, Question G.c. AGA understands why PHMSA attempted to use these values for its calculations; however, AGA reminds PHMSA that a single pipeline can undergo multiple “assessments” in a calendar year. Therefore, the values reported in Question F.6.a. are not representative of independent pipeline mileage inspections. For example, a newly installed pipeline will often be in-line inspected for material and construction defects prior to undergoing the initial subpart J pressure test. This would equate to those same pipeline miles being represented twice within the value reported in F.6.a. Another example is a pipeline assessed with a single combination tool. Each inspection method is reported independently on the Annual Report. Therefore, AGA urges PHMSA to explore a different methodology in attempting to determine the percentage of non-HCA pipeline miles that have previously received an integrity assessment.

\(^{104}\) Values from Table 3-10 and Table #.19. PRIA.
AGA’s previous comments about the inaccuracies of the unit costs related to in-line inspection, pressure testing, and direct examination are also applicable in this portion of the impact assessment. AGA reminds PHMSA of the variance in unit costs for PHMSA’s BPJ and AGA member reported data for the three referenced assessment methods for intrastate pipelines. Table V-7 provides the comparison.

**Table V-7: Unit Cost Comparison for Each Assessment Method**

<table>
<thead>
<tr>
<th></th>
<th>In-Line Inspection</th>
<th>Pressure Testing</th>
<th>Direct Assessment &amp; Others</th>
</tr>
</thead>
<tbody>
<tr>
<td>PHMSA’s BPJ</td>
<td>$4,594(^{105})</td>
<td>$203,556(^{106})</td>
<td>$42,750(^{107})</td>
</tr>
<tr>
<td>AGA Data</td>
<td>$15,594</td>
<td>$441,410</td>
<td>$119,276</td>
</tr>
</tbody>
</table>

Using AGA’s unit cost data but PHMSA’s estimates for the percentage of intrastate pipelines located in MCAs that will utilize each assessment method (Table 3-34) and PHMSA’s estimated intrastate MCA mileage for each integrity assessment method (Table 3-35), AGA calculated the total cost for expansion of assessments outside of HCAs for intrastate transmission pipelines. See Table V-8 for these estimates. PHMSA’s annual total to expand integrity management is only 38% of what AGA estimates. This is a substantial understatement of costs in the PRIA.

**Table V-8: Compilation of PHMSA’s Presumed Costs for Assessments vs. AGA Member Data**

<table>
<thead>
<tr>
<th></th>
<th>ILI</th>
<th>Pressure Test</th>
<th>Direct Assessment &amp; Other</th>
<th>Annual Total</th>
<th>15 Year Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>PHMSA’s BPJ(^{108})</td>
<td>$533,922</td>
<td>$2,588,687</td>
<td>$3,092,380</td>
<td>$6,214,989</td>
<td>$93,224,835</td>
</tr>
<tr>
<td>AGA Data</td>
<td>$1,926,379</td>
<td>$5,620,621</td>
<td>$8,627,631</td>
<td>$16,174,630</td>
<td>$242,619,452</td>
</tr>
</tbody>
</table>

Despite PHMSA’s significant underestimate of the cost to comply with this regulation, AGA maintains its commitment to perform reliability assessments outside of HCAs. AGA requests that PHMSA accurately estimate the costs to comply with this regulation. Without accurate impact assessments, the regulated natural gas distribution industry, which operates thousands of miles of intrastate transmission pipelines, will be left to explain to their respective state regulators (utility commissions) why there is such a large discrepancy between PHMSA’s cost estimates and their own.

Further, the lack of reasonable cost estimates impedes reviewers’ opportunities to comment on the Proposed Rule and its impacts. Without accurately accounting for the costs associated with this proposed regulation, even the portions supported by industry, the Office of Management and Budget, and thus the public, will never be able to truly understand the economic impact of this rulemaking until it is too late and the heavy burdens of cost are borne by the public with much less benefit than predicted by PHMSA.

(E) **PHMSA’s Failure to Account for Costs of Material Verification**

\(^{105}\) Table 3-10 of the PRIA.
\(^{106}\) Table 3-19 of the PRIA.
\(^{107}\) Table 3-21 of the PRIA.
\(^{108}\) Table 3-36 of the PRIA.
As AGA describes in comments on Material Verification (§192.607), AGA is seriously concerned with PHMSA’s failure to acknowledge the costs associated with Material Verification. AGA recognizes that in the costs associated with repairs in Table 3-63, PHMSA provides reference to costs for Material Verification, but this is only for a very small subset of the pipelines where §192.607 is applicable. Specifically, there are two subsets of pipelines that are impacted by the changes in the repair criteria that PHMSA has not addressed in Section 3.2.4 of the PRIA:

A. Pipelines in HCAs that are not applicable to MAOP Verification (§192.624)
B. Pipelines in Class 3 & 4 locations that are applicable to Material Verification

Furthermore, the costs provided by PHMSA for the one identified subset of pipelines subject to §192.607 do not appear to be utilized by PHMSA in its regulatory impact assessment within Section 3.2.2 of the PRIA.

AGA has attempted to estimate the actual costs to comply with §192.607. AGA’s members reported a cost of $80,000 per sample, slightly higher than PHMSA’s estimated cost of $75,000 per sample for Material Verification. See PRIA, page 122. Utilizing the same mileage as PHMSA for the applicability of Material Verification, 291 miles, and the regulatory requirements within the proposed §192.607, AGA has attempted to estimate the actual cost to comply with §192.607 – to replace the cost assessment, which is absent from the PRIA. If AGA assumes that each of the 291 miles is a separate population, and applies the sampling criteria within §192.607(d)(3)(ii)(B), of one sample for each mile, AGA estimates a total cost to comply with §192.607 as $23,280,000. Even when distributed across a 15-year time interval, AGA concludes that the annual compliance cost discounted at 7% for Material Verification is $1.61 Million. In order for PHMSA to provide an accurate estimate of costs, these actual costs need to be reflected in Table 3-57, which is intended to encompass all of the regulatory requirements within Topic Area #1 of the PRIA.

(F) Discussion of Benefits
Safety Benefits

AGA disagrees with PHMSA’s methodology for determining the safety benefits associated with the proposed regulations within Topic Area 1 and supports the comments from ICF International (ICF) on the flaw in PHMSA’s methodology. In essence, PHMSA has allowed one incident to drive the estimation of impact for 297,885 gas transmission pipeline miles. As ICF has stated109, this single incident contributed 98.9% of the total consequences from the 23 incidents since 2003. In the report, “ICF conducts such an analysis assuming that consequences follow a power law distribution. This analysis suggests a better estimate of the average consequences to be expected from incidents in HCA areas from causes detectable by modern integrity assessment methods as approximately $6.7 million rather than the $23.4 million calculated by a simple average of the 23 incidents.” AGA encourages PHMSA to pursue a different approach in the finalized regulatory impact assessment supporting the Final Rule to ensure that the estimates are reasonable and justifiable and not so heavily skewed by a single data point.

Cost Savings Benefits

PHMSA’s failure to account for the costs associated with Material Verification are compounded by the fact that PHMSA seems to believe that the requirements within §192.607 actually represent a cost savings. PHMSA

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proceeds to estimate the total cost to perform “cutouts” per §192.107(b) is $228 Million for the estimated 291 miles of gas transmission pipelines in HCAs, Class 3, and Class 4 locations with inadequate material records. This assumes a rate of 13.2 cutouts per mile at $75,000 per cutout.

PHMSA’s analysis is premised on the misapplication of §192.107(b), which was not codified for application to in-service buried pipelines. Instead, §192.107(b) references an appendix to code that addresses how to handle pipe material that is readily accessible and not yet installed. §192.107 is located within Subpart C, Pipe Design, a section of pipeline safety regulations that can only be applied to new pipelines and does not apply retroactively. Given this context, there is simply no support that §192.107 would require an operator to perform tensile tests on an existing, buried pipeline because records of material properties, not required by the regulations, were not available. PHMSA’s attempt to use this basis for a “cost savings” for operators is misleading and inappropriate.

Even if §192.107(b) were to apply to existing pipelines, PHMSA methodology is flawed. First, PHMSA has neglected to consider §192.107(b)(2) anywhere within the PRIA. Many operators already operate segments using the SMYS of 24,000 p.s.i. as allowed in §192.107(b)(2). For a segment operating at the §192.107(b)(2)-allowed SMYS of 24,000 p.s.i., the requirements of §192.607 represent a cost without any benefit. Second, PHMSA compares the costs to comply with §192.107(b) for material verification with the compliance costs for “re-establishing” MAOP. These two costs reference two completely different regulatory requirements and there is no technical justification for their comparison.

By misapplying an existing regulation, neglecting to consider §192.107(b)(2), and improperly comparing two different proposed regulatory requirements, PHMSA has incorrectly concluded the requirements of §192.607 will represent a $2.4 billion cost savings to operators over 15-years. AGA strongly encourages PHMSA to reconsider this portion of the PRIA as support for the final rule.

(2) Integrity Management Program Process Clarifications

PHMSA includes eight different “clarifications” to existing Subpart O Integrity Management regulations:

(1) Clarify management of change process requirements for IM programs
(2) Clarify threat identification requirements for time-dependent threats
(3) Clarify requirements related to baseline assessment methods
(4) Clarify repair criteria for remediating defects discovered in HCA segments
(5) Clarify P&M measures based on risk assessments, to include more examples
(6) Clarify P&M measures for covered segments for outside force damage
(7) Clarify requirements for periodic evaluations and assessments, including some specifically for plastic transmission lines
(8) Written notification for a 6-month extension of 7-year reassessment interval

AGA first questions PHMSA’s choice in terminology: “these clarifications, with few limited exceptions, would not alter, change or revise the requirements in Subpart O." By simply saying that all changes to Subpart O are “clarifications,” PHMSA minimizes and mischaracterizes the true impact of its new regulatory requirements in this section of the Proposed Rule. This mischaracterization serves to mislead the audience in its review of the PRIA. In the following portion of AGA’s comments and in the topic specific comments throughout this document, AGA highlights how these changes are not in fact clarifications, but are additional new and unjustified requirements.
Management of Change: PHMSA states that since the changes “are not new requirements, PHMSA concluded that this requirement would not impose an additional burden on pipeline operators.” AGA addresses the concerns with this statement in the next section of these comments: (3) Management of Change Process.

Threat Identification Requirements: Again, PHMSA has mischaracterized the significant implications that the changes to §192.917(b) and (c) will have on the manner by which operators perform risk analysis and risk assessments. The PRIA does not take into account the cost to gather data on the 19 newly proposed datasets, conduct field verification and validation of existing and new datasets, costs to integrate the existing and new datasets, upgrades to mapping systems and other data management systems, staff or the hiring of an outside firm to manage and execute a quantitative risk model, SME bias control measures, worst-case scenario analysis of each HCA, or the evaluation of potential risk reduction associated with various candidate risk reduction activities. In addition, PHMSA assumes that all operators have access to system data through a comprehensive GIS. This is an incorrect assumption and the costs for operators to create and maintain a GIS are not accounted for in the PRIA. AGA discusses in detail the costs associated with modifying existing risk assessment programs to meet PHMSA’s new requirements in Section IV.E. 3 of these comments.

Baseline Assessment Methods: As discussed in Section IV.E.2 of these comments, PHMSA has underrepresented the impact of limiting the use of Direct Assessment as an integrity assessment method. For example, PHMSA states that “as a practical matter, DA is typically not chosen as the assessment method if the pipeline can be assessed using ILI. Therefore, this requirement would not impose a significant additional burden on pipeline operators.” AGA can only agree with that statement if all regulators, federal and state, agree upon a definition of “able to accommodate inspection by an in-line inspection tool” as discussed in Section IV.C of these comments. While the use of ILI tools to conduct integrity inspections continues to increase year over year, it is important to recognize that a significant percentage of intrastate transmission pipeline segments are still assessed for corrosion using Direct Assessment. If regulators begin to limit the use of DA even for pipelines where only a robotic or tethered in-line inspection tool is capable of collecting data, many of PHMSA’s assumptions about the impact of this rulemaking will be voided.

Repair Criteria: As discussed in AGA’s comments on Repair Criteria, AGA is concerned with PHMSA’s lack of acknowledgement on the impact that modifications to transmission pipeline repair criteria will have on pipeline operators, both inside and outside HCAs. PHMSA has failed to account for the new prescriptive repair criteria for assessments in Class 3, Class 4 and MCA locations. As discussed in a previous section of these comments, AGA is concerned with the mileage estimate PHMSA has concluded for the MCA mileage subject to integrity assessment requirements - 7,379 miles (Table 3-33). However, for purposes of these comments, AGA will utilize this mileage to portray the inadequacies in PHMSA’s cost estimate for this topic area.

Using all of PHMSA assumptions but combining the mileage in HCAs that are impacted by the new repair criteria requirements, 2,407 miles per year, with the MCA mileage, 591 miles, AGA has recreated Table 3-62 below in Table V-9:

<table>
<thead>
<tr>
<th>Table V-9: Estimation of Repair Conditions (PHMSA PRIA Corrected)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Component</td>
</tr>
<tr>
<td>HCA &amp; MCA miles assessed per year</td>
</tr>
<tr>
<td>Schedule repair conditions per miles assessed</td>
</tr>
<tr>
<td>---------------------------------------------</td>
</tr>
<tr>
<td>Expected scheduled repair conditions per year</td>
</tr>
<tr>
<td>180-day conditions</td>
</tr>
<tr>
<td>Expect 180-day conditions per year</td>
</tr>
</tbody>
</table>

On average AGA’s estimates for repair criteria are 1.25 times greater than PHMSA’s estimates.\(^{110}\) Combining the additional number of annual repairs with the increased repair costs results in an overall underestimation by PHMSA’s PRIA of the costs related to the repair criteria contained in the Proposed Rule.

Ultimately, this underestimation is made worse by PHMSA’s flawed methodology in assuming that all of PHMSA’s prescriptive repair criteria fall within existing industry standards for repair. Essentially, PHMSA’s flawed methodology assumes that every repair condition identified would ultimately be repaired by the operator—regardless of the condition’s severity. As discussed in AGA’s comments on Repair Criteria, this is simply not correct. PHMSA has proposed ultra-conservative repair criteria, which would require operators to make additional “repairs” on pipelines that are unnecessary and unwarranted. AGA supports the analysis performed by ICF, Cost and Benefit Impact Analysis of the PHMSA Natural Gas Gathering and Transmission Safety Regulation,\(^{111}\) which estimates a cost of $591 million over 15 years for MCA field repair of conditions and $1.6 billion for missing costs for non-HCA and non-MCA field repair of damages on transmission lines.

Preventative & Mitigative Measures: AGA highlights the extreme confusion created by PHMSA’s modifications to the regulatory text in §192.935 in our comments on preventative and mitigative (P&M) measures within this document. AGA reminds PHMSA that due to the manner in which the text was written, all thirteen listed “examples” of P&M measures would have to be performed for operators to comply with the proposed §192.935. Therefore, there is an acknowledged and extremely high cost associated with this section of the rulemaking. Unless PHMSA rewrites the regulatory text in such a way that all listed P&M measures are considerations and not requirements for an operator to be compliant, PHMSA needs to account for these additional costs in the regulatory impact assessment.

Periodic Evaluations and Assessments: AGA has no comments on this section.

Reassessment Interval: AGA has no comments on this section.

(3) Management of Change Process Improvement

PHMSA’s estimated costs associated with its proposed revisions related to Management of Change (MoC) significantly underestimate the impact that the Proposed Rule would have on operators. First, PHMSA’s costs are premised on the assumption that of the 350 operators that do not have IM programs only 70 operators would need to develop processes to more formally implement the new MoC rule requirements. See PRIA, page 80. PHMSA’s assumptions are not supported and are inaccurate. First, there is nothing to suggest that any operator that does not have an IM program would have a formal MoC process currently in effect. AGA believes that a much higher estimate of operators would be required to establish a new process or revise existing MoC procedures to comply with the new MoC criteria proposed in the regulation. In addition, PHMSA has failed to account for the

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\(^{110}\) See AGA’s Comments on Repair Criteria for a full breakdown of AGA’s estimates for the cost to repair using each of the repair methods

\(^{111}\) ICF International. Citation.
costs for an operator with an IM program to expand its MoC process to cover all transmission pipelines and revise it to match the changes as listed by PHMSA in the Proposed Rule. Based on AGA’s survey of member companies, 32 of 38 respondents indicated that they would be required to take some action to update or create a MoC process consistent with the Proposed Rule.

PHMSA assumes that a “typical pipeline system has 8 compressor stations and 3 piping sections” and that a typical pipeline system would have one compressor station change event and three piping section change events per year. See PRIA, page 79. These assumptions lead to PHMSA’s estimate that a company would only have 4 MoC events annually. Responses to AGA’s survey of member companies estimated the number of MoC occurrences ranged from 1 to 450 events annually, with the average number estimated at 60 events per year. This is significantly higher than the PRIA’s estimate of four MoC events annually. The range of values obtained by AGA’s survey of its member companies represents companies with tens of miles of affected transmission pipeline to those with several thousands of miles. The scope of PHMSA’s MoC proposal also includes other changes that are in addition to the physical changes that PHMSA estimated. See proposed §192.13(d) (Technical, Design, Physical, Environmental, Procedural, Operational, Maintenance, and Organizational). The PRIA cost analysis does not account for this significant increase in the scope of MoC events.

PHMSA estimated in the PRIA document (Table 3-68) that it would cost $3,492 per MoC event. The accuracy of $3,492 is questioned, due to responses from an AGA survey that included 12 operating company responses. The median cost of MoC change was reported as $7,695.

PHMSA’s cost analysis estimates that it would only cost a company $2,277-$9,902 to implement an MoC process (Table 3-67). AGA’s survey results of member companies suggest that these estimates are extremely understated and that the average cost would be nearly $2 Million. Table V-10 below provides a detailed breakdown of the actual costs that would be experienced by AGA’s membership in the implementation of MoC as PHMSA has proposed in the regulation.

Table V-10: AGA Member Data for Implementation of PHMSA’s proposed MoC requirements (per Company)

<table>
<thead>
<tr>
<th>Activity</th>
<th>Low Estimate</th>
<th>High Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Hours</td>
<td>Cost</td>
</tr>
<tr>
<td>Review existing MoC Procedures within scope of Subpart O</td>
<td>59</td>
<td>$5,800</td>
</tr>
<tr>
<td>Revise and expand scope of procedures beyond Subpart O</td>
<td>151</td>
<td>$13,674</td>
</tr>
<tr>
<td>Establish procedures beyond Subpart O</td>
<td>322</td>
<td>$26,209</td>
</tr>
<tr>
<td>Notify personnel and provide implementation guidance and instruction beyond Subpart O</td>
<td>283</td>
<td>$34,180</td>
</tr>
<tr>
<td>AGA’s Total for Costs Represented in Table 3-67</td>
<td>756</td>
<td>$74,063</td>
</tr>
<tr>
<td>Annual count of MoC Orders beyond Subpart O</td>
<td>371</td>
<td>$34,037</td>
</tr>
<tr>
<td>IT Integration beyond Subpart O</td>
<td>1375</td>
<td>$691,110</td>
</tr>
<tr>
<td>Other Costs Not Considered in PRIA</td>
<td>120</td>
<td>$1,040,400</td>
</tr>
<tr>
<td>AGA’s Average Total Costs</td>
<td>2681</td>
<td>$1,845,410</td>
</tr>
<tr>
<td>PHMSA’s Total from Table 3-67</td>
<td>20*</td>
<td>$1,980</td>
</tr>
</tbody>
</table>
Implementation of the proposed change to the MoC process will require the development of a software user interface and database for MoC tracking. In a survey of operating companies with formal MoC processes, 85% of respondents reported the expanded MoC requirement will require the use of an electronic system for managing MoCs. This will be necessary to properly organize and track the progress of multiple changes occurring simultaneously. Notably absent from the estimate on Table 3-67 is the cost for developing and deploying a software application for managing and documenting the change process.

The cost to develop a process, procedures, and an electronic tracking system is also grossly underestimated. The management and implementation of this type of system is also not adequately considered in the PRIA. The distributed nature of natural gas transmission pipeline operations that includes multiple changes occurring in multiple operating areas simultaneously requires the use of a central electronic system, which impacted individuals can access from any operating area office. In addition, an electronic system is needed to efficiently manage MoC submissions, reviews, and approvals by multiple people in multiple areas. The development and implementation of this type of application is costly, time consuming, and resource intensive; the cost for which is not adequately captured in the PRIA. Using actual operator data, AGA estimates the initial cost of an electronic program is significant, and can range from $20,000 to $12,000,000. This will be costly for those companies that do not currently have an electronic system, but may now need to purchase and implement such a system to comply with the expanded MoC requirements contained in the Proposed Rule.

If the proposed MoC requirements become effective, operators will need to revise existing plans, procedures and work practices mentioned above to include these new requirements or create new plans, procedures and work practices to meet these new requirements. In addition to the effort for reviewing and revising these plans, procedures and work practices, employee training, both engineering and operating personnel, would need to be enhanced to address these additional requirements. The required documentation and approval processes prior to these routine work activities would become overly cumbersome and would cause delays in the routine work activities being performed. This has not been taken into account in the PRIA.

(4) Corrosion Control Requirement Changes

In the Corrosion Control portion of the PRIA, PHMSA combines seven regulatory changes that relate to corrosion control.

1. Perform pipe coating assessment for steel onshore transmission pipe installed in ditch
2. Protective coating strength requirements. Requirements also provided as a P&M measure for covered segments.
3. Perform pipe coating assessment when there are indications of compromised integrity
4. Remedial action to correct external corrosion deficiencies prior to the next monitoring interval (NTE 1 year) in most locations, and for covered segments in HCAs where the CP reading is below the level of protection in Subpart I, 6 months as a P&M measure.
5. Close interval survey required in accordance with Appendix D and as a P&M measure
6. Additional stray/interference current remedial action, including 6-months deadline for addressing and provided as a P&M measure for covered segments.
7. Develop and implement an internal corrosion control monitoring and mitigation program, which includes a gas stream monitoring program, including semi-annual program reviews and provided as a P&M measure for covered segments in HCAs.
AGA has provided comments in the three sections of this document focused on corrosion related issues. In this section, AGA provides additional discussion regarding the PRIA’s assumptions on the costs and burdens of complying with PHMSA’s new proposals associated with Corrosion Control.

**Internal Corrosion Control Monitoring and Mitigation Program:** For the new regulatory requirements related to internal corrosion monitoring and mitigation in §192.478, PHMSA estimates the industry as a whole will need to install 40 additional gas monitors at a cost of $10,000 each for a total of $400,000. See PRIA, page 91. As discussed in AGA’s comments on Subpart I, AGA reminds PHMSA that local distribution companies have a dependent relationship with long-haul, interstate transmission pipeline operators to transport gas to their system and may purchase gas from several different suppliers. As the proposed regulation is written, these local distribution companies would be required to install gas monitoring equipment at all of the custody transfer locations (e.g., gate stations), which would require the installation of gas monitoring equipment at significantly more than 40 locations. AGA estimates its member companies will need to install at least 437 additional gas monitoring devices, which ultimately would cost as much as $66 Million for AGA’s membership alone.

**Cathodic Protection:** PHMSA states that in Appendix D “some wording changes are proposed to better define IR drop, but the technical intent is unchanged.” However, as AGA has described in the comments on Appendix D, the regulatory text changes are not simply clarifications in addressing IR drop. These changes will greatly impact distribution pipeline operators and would ultimately cause operators to replace existing galvanic CP systems with impressed current (rectifier) CP systems, which would result in the installation of additional CP test stations. In Table 3-73, PHMSA estimates an additional 7,949 test stations at $500 each. Based on the actual installation costs, AGA membership reports that these test stations cost up to $22,000 each to install, depending on field conditions, especially in urban areas requiring excavation within improved right of ways. Using PHMSA’s own estimate of 7,949 stations, this would equate to nearly $175 Billion for compliance with the new Appendix D requirements compared to the $3.9 Billion PHMSA has estimated in the PRIA.

**Pipeline Inspection Following Extreme Weather Events**

PHMSA has estimated the impact and benefits associated with the proposed inspections following extreme events in the PRIA. Initially, AGA notes that there are several inaccuracies with PHMSA’s analysis in the PRIA that make it difficult to evaluate PHMSA’s proposal as well as provide meaningful comments. First, the PRIA incorrectly states that the proposed inspection following extreme weather events would apply to both onshore and offshore pipelines and that §192.613(a) would be modified. See PRIA 92. According to the proposed regulatory text, the proposed inspection would only apply to onshore transmission pipelines and §192.613(a) is not proposed to be modified.

Second, PHMSA estimates the regulatory impact associated with reviewing existing extreme weather surveillance and patrol procedures to validate their adequacy and consistency with the proposed regulation ranges from 2 hours at the low end and 1 hour at the high end. PHMSA then estimates the costs based on these ranges of hours. There is a clear error in PHMSA’s estimates, since the high-side estimate is 50% lower than the low-side estimate. See PRIA Table 3-78, page 92-93.

Third, PHMSA’s description in the PRIA of when the surveillance must occur differs from that in the proposed regulatory text. The PRIA states that surveillance must occur “within 72 hours of the cessation of an event or as soon as possible once personnel and equipment can safely access the area.” See PRIA, page 92.
However, the regulatory text defines the “cessation of the event” as when the area can be accessed safely, and provides operators 72 hours from that point to conduct the surveillance.

Finally, PHMSA assumes that the patrols or remediation would have been completed absent the Proposed Rule, but at a later time. As such, PHMSA does not account for any costs associated with these activities. However, because PHMSA does account for incidents averted as a result of the proposed patrol requirements, they are acknowledging that at least some additional patrols or remediations would occur as a result of the Proposed Rule. PHMSA has either claimed benefits from the rule that should not have been claimed or has failed to account for incremental costs incurred from the Proposed Rule. Additionally, due to the prescriptive timing of many transmission pipeline patrols, the timing of a special extreme weather event patrol may not allow for the special patrol to substitute for the scheduled patrol.

PHMSA asserts that it has justified this new requirement based on an October 1994 incident and 85 reportable incidents from 2003 to 2013 “in which storms or other severe natural force conditions damaged pipelines and resulted in their failure.” However, based on the incident data provided in the PRIA, it is impossible for stakeholders to evaluate which 85 incidents PHMSA is referencing or to evaluate the appropriateness of inclusion. PHMSA’s estimate of the related benefits is significantly lacking. PHMSA estimates that 0.5 incidents will be averted each year due to these proposed requirements. PHMSA’s assumption is based solely on PHMSA’s asserted best professional judgment, with no elaboration or technical justification regarding the basis for how the 0.5 figure was derived. From this, and PHMSA’s general estimate on the cost of an incident, PHMSA estimates annual benefits of the proposed requirements. Such an unsupported estimate is not a valid estimate and does not satisfy PHMSA’s statutory obligation to consider the reasonably identifiable or estimated benefits of its proposed regulatory change. This negates any identified benefit associated with the use of this unfounded estimate. As in many instances in the Proposed Rule and PRIA, PHMSA is essentially saying, “the rule is justified because we said so, based on data we will not or cannot share with industry’ and then further elicits comments for industry to provide the accompanying data to support any submitted comments on PHMSA’s use of BPJ.

(6) MAOP Exceedance Reports and Records Verification

PHMSA’s estimate of the proposed “MAOP records verification” impacts misstates the extent of historic recordkeeping requirements, mischaracterizes what would be required under the Proposed Rule, and significantly underestimates the impact of the Proposed Rule.

As proposed, §192.13(e) would enlarge the magnitude of records required to document compliance with all of Part 192, would impose stringent new standards to validate those records, and would require the documentation of material properties. Proposed §192.619(f) would retroactively impose a new requirement to maintain documents used to establish MAOP for the life of a pipeline. In addition to transmission pipelines, these new requirements would apply to distribution pipelines and in some cases gathering lines.

PHMSA describes proposed §192.13(e) as elaborating on the general recordkeeping requirement in §192.603: General provisions. See PRIA, page 95. Contrary to PHMSA’s statements, §192.603(b) does not contain a general requirement to maintain records for operating, maintaining, and repairing the pipeline. Instead,

113 AGA’s significant concerns related to PHMSA’s estimated average cost per incident are discussed in Section V.
\$192.603(b) merely requires operators to keep records necessary to administer its manual of written procedures for conducting operations and maintenance activities and for emergency response. Nothing in either \$192.603(b) nor \$192.605: Procedural manual for operations, maintenance, and emergencies, imposes an obligation to maintain records regarding the operation, maintenance, or construction of a specific pipeline.\textsuperscript{114}

For justification of the proposed MAOP record verification requirements, PHMSA points to Congressional mandates from the 2011 pipeline safety authorization. See PRIA, page 95. However, PHMSA’s justification is lacking. Section 23 of the Act merely requires that operators perform a records search, evaluate whether records reflect physical and operational characteristics of pipelines, and document for which pipelines records are insufficient to confirm the established MAOP.\textsuperscript{115} For these pipelines with insufficient records, the Congressional mandate requires that operators reconfirm the MAOP. Importantly, the Section 23 record verification requirements only apply to transmission pipelines in Class 3 and 4 locations and Class 1 and 2 HCAs.

There is no statutory requirement in Section 23 or elsewhere to require all pipeline operators retroactively document compliance with the regulations, maintain records that are reliable, traceable, verifiable and complete, re-establish material properties, or retroactively document how a pipeline’s MAOP was established, as would be required by proposed \$192.13(e) and \$192.619(f). Instead, PHMSA’s authority is limited by its obligation to consider the costs and benefits associated with the requirement. See 49 U.S.C. \$60102(b)(2)(C), (D).

PHMSA’s sole basis for the costs associated with proposed \$192.13(e) is its prior estimate that it would take operators 20 hours to complete a records review for 1,440 annual reports that PHMSA required in response to the Congressional mandate in section 23(a). First, PHMSA’s estimate of 20 hours is extremely understated. AGA reminds PHMSA that there was never a federal regulatory obligation to maintain these records, much less retain them in an organized fashion. As a result, the process of identifying and evaluating these records for the estimated 4,400 miles\textsuperscript{116} of pipeline subject to the Section 23 mandate is considerably more than PHMSA’s estimate of 20 hours. Second, for the annual report, PHMSA was requesting data on transmission pipelines in Class 3 and 4 locations and Class 1 and 2 HCAs. However, proposed \$192.13(e) would apply to all transmission pipelines as well as distribution pipelines and in some instances gathering lines.

The more significant flaw in PHMSA’s estimate of costs is that PHMSA is merely assessing the cost of verifying records, whereas, as described above, proposed \$192.13(e) imposes obligations well beyond “verifying” existing records. Proposed Section 192.13(e) would require existing pipelines to newly document compliance with Part 192, impose a more stringent authentication requirement on existing records, and require material

\textsuperscript{114} AGA notes that \$192.709 requires that operators maintain for transmission lines limited repair records, as well as limited records of patrols, surveys, inspections and tests. This section also does not require the same sort of broad recordkeeping requirements contemplated by the proposed revisions and was only added in 1996.

\textsuperscript{115} PHMSA acted upon the Congressional mandate by publishing Advisory Bulletin 12-06, which noted that operators would need to evaluate and report on the adequacy of records. Natural gas operators have provided PHMSA with this information through the annual reports since 2012. Based on these actions, AGA considers the Congressional mandate found in Section 23(a) to be acted upon and complete, and that the requirements found in proposed Section 192.13(e) to be new requirements that are outside the scope of any Congressional mandate.

\textsuperscript{116} This estimate is taken from PHMSA’s calculation of the mileage of pipelines with insufficient records to confirm MAOP provided in Table 3-26 of the PRIA.
verification\textsuperscript{117} where records do not meet the more stringent requirements. PHMSA has failed to address these costs.

PHMSA also has failed to address any benefit associated with proposed §192.13(e). See PRIA, page 128. Since PHMSA did not have information to estimate the benefits of this provision from the pre-statutory costs and benefits of such an expansive and burdensome recordkeeping requirement, PHMSA’s proposed §192.13(e) cannot be said to be based “upon a reasoned determination that the benefits of the intended standard justify its costs.” See 49 U.S.C. § 60102(b)(5).

Based on this deficient analysis of the costs and lack of any estimated benefit of such an expansive and burdensome recordkeeping requirement, PHMSA’s proposed §192.13(e) cannot be said to be based “upon a reasoned determination that the benefits of the intended standard justify its costs.” See 49 U.S.C. § 60102(b)(5).

(7) Launcher and Receiver Pressure Relief
AGA has no comments on this portion of the PRIA.

(8) Expansion of Gathering Regulations
AGA supports the analysis and comments provided by API and in the ICF Study: Cost and Benefit Impact Analysis of the PHMSA Natural Gas Gathering and Transmission Safety Regulation Proposal, which calculates, using actual industry data, that the PRIA misrepresents the costs associated with compliance for gas gathering lines by $28.8 Billion.

PHMSA’s Reliance on the Social Cost of Methane
Carbon dioxide and methane are greenhouse gases. The social cost of carbon (SCC) is an estimate of the monetary value of the damages from the release of an additional unit of carbon dioxide. Similarly, the social cost of methane (SCM) is the monetary value of the damages from the release of an additional or marginal unit of methane.

Federal agencies have used the Social Cost of Carbon values to estimate the climate benefits of particular rulemaking. However, the Social Cost of Methane has not been widely utilized to estimate climate costs or benefits from an agency rulemaking.

PHMSA estimated the climate change effects of the rule by multiplying the volume of natural gas lost or captured by estimates of the SCM. This monetary value represents either a cost or benefit associated with methane emissions depending on if the methane gas is released into the atmosphere (as in the case of blowdowns from pressure testing and in-line inspections) or emissions averted due to capture or incidents avoided. Similarly, for natural gas combusted or captured and not combusted, the resulting carbon dioxide emissions lost or saved are multiplied by estimates of the SCC to arrive at a monetary value for the climate change costs and benefits of carbon dioxide released and captured.

AGA identifies at least three concerns with the approach PHMSA used.

\textsuperscript{117} The flaws in PHMSA’s assumptions regarding the cost of Material Verification are addressed in AGA’s comments on proposed Section 607.
1) The process for developing estimated values for the social cost of methane is based on a single study (Marten et. al., 2014). The process was inadequate and without sufficient expert and public input and additional peer review.

2) Discontinuity in the comparison of costs and benefits of climate change effects from other costs and benefits in the rulemaking. Climate benefits and costs are estimated using global impact models. However, the costs associated with this rulemaking are domestic (e.g. value of captured gas, costs of incidents). This disconnect between the global costs and benefits and the domestic costs and benefits creates a fundamental problem with the cost-benefit analysis used here.

3) Methodological estimates overstated the estimated methane released from blowdowns associated from pressure testing and ILI and therefore overestimated the climate change effect costs from this activity.

**Process for developing estimated values of the social cost of methane (SCM):** The process for developing estimated values of the social cost of methane (SCM) is inadequate, especially compared with the process to develop estimated values for the social cost of carbon (SCC). The process used to develop the SCC began as an interagency working group convened by the Council of Economic Advisers and the Office of Management and Budget in 2009 and 2010. The process involved a modeling exercise and review of inputs. Estimates developed through this exercise were intended to be used in rulemakings.

The Interagency Working Group (IWG) had a wide variety of agency and expert input. The IWG on the Social Cost of Carbon included participation by the Council of Economic Advisors, The Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and the Department of Treasury. The interagency process developed SCC estimates and reported these values in a 2010 interagency Technical Support Document. These values were revised in subsequent 2013 and 2015 updates. The Interagency Working Group on the Social Cost of Carbon notes that “rigorous evaluation of benefits and costs is core tenet of the rulemaking process” and that “the current estimate of the SCC has been developed over several years, using the best science available, and with input from the public.”

By stark contrast, the process to develop the SCM went through a much less rigorous process with considerably less input from scientific experts and with a limited review process that included no input from the public. The same level of scrutiny and evaluation for the SCC was not applied to development of the estimates of the SCM used in this rulemaking.

NERA Economic Consulting, in a technical analysis related to the Regulatory Impact Analysis for the Environmental Protection Agency’s proposed emissions standards for methane and volatile organic compounds in the oil and natural gas sectors, addressed a number of technical issues with both the development and use of the current Social Cost of Methane values. See Appendix E of these comments.

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NERA Economic Consulting’s analysis provided a quantitative assessment of the sensitivity of the use of this RIA’s estimates of benefits and developed alternative assumptions for SC-CH4 estimates that were as much as 90% and 94% lower than the SC-CH4 estimates used in rulemaking. This raises concerns that the estimates used in PHMSA’s rulemaking may be significantly overstating the climate change costs and benefits associated with methane.

Discontinuity in Costs and Benefits: Per the NERA Economic Consulting Analysis, PHMSA’s reliance on SCM estimates that reflect global costs and benefits rather than domestic costs and benefits is “a practice that is contrary to the Office of Management and Budget’s (OMB’s) Circular A-4 (OMB, 2003) and inconsistent with the theoretical underpinnings of benefit-cost analysis that endow the method with its ability to guide a society towards policies that will improve its citizen’s well-being. Circular A-4 calls for use of domestic benefits, and notes that any estimates of non-domestic benefits should be presented separately.” At the very least, PHMSA should disaggregate the domestic climate costs and benefits from carbon dioxide and methane in this rulemaking from the global values in order to make a proper domestic evaluation in comparison with other costs and benefits weighted in this rulemaking.

PHMSA’s methodology errors: For table B-3, PHMSA used total gas emissions instead of methane emissions and therefore overestimated the costs associated with blowdown events.

Estimated total gas and methane emissions from blowdowns from ILI upgrades in Table 3-54 is incorrect. The estimates incorrectly use data from Table 3-49 for emissions from pressure tests instead of Table 3-53 for ILI upgrades. This has the effect of overstating estimated emissions from blowdowns and therefore climate costs.

VI. ENVIRONMENTAL IMPACT ASSESSMENT

PHMSA’s Environmental Assessment Fails to Consider Direct Impacts from the Proposed Rule

PHMSA has prepared a draft Environmental Assessment (EA) in accordance with the National Environmental Policy Act of 1969 (NEPA) to analyze the potential environmental consequences of adopting the Proposed Rule. PHMSA considered two alternatives for each topic in the Proposed Rule: the no action alternative and the proposed action. PHMSA concludes that the proposed action alternative is not expected to result in adverse environmental impacts and may result in beneficial impacts. In fact, the EA states that the Proposed Rule “would have a net positive impact to human health and the physical environment through a reduction in pipeline failures and increased safety to pipeline workers and the public.” Draft EA at 18. Based on these conclusions, PHMSA has preliminarily determined that the Proposed Rule would have no significant impact on the environment.

AGA believes that PHMSA has failed to consider several topics in the Proposed Rule that would have direct environmental impacts, as well as several additional adverse environmental impacts and consequences not considered by PHMSA that are directly associated with the Proposed Rule.

119 “Circular A-4 states ‘Your analysis should focus on benefits and costs that accrue to citizens and residents of the United States. Where you choose to evaluate a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately.’ (OMB, 2003, p.15)” (NERA Economic Consulting, Page 1)
**PHMSA’s Evaluation of the Proposed Action**

PHMSA’s description of the Proposed Action, Section 3.3, mischaracterizes many aspects of the Proposed Rule and fails to consider several topics that would have a direct impact on the environment.

- **“Integrity Management (IM) Program Process Clarifications,” 3.3.1:** PHMSA’s Proposed Rule does not “clarify” the existing IM Program Process, but instead imposes significant new requirements on operators to maintain a system-wide Management of Change process, identify new threats to pipelines, and implement more prescriptive repair criteria. PHMSA’s revisions to assessment methods would result in more pipelines being modified to accommodate in-line inspection tools for the additional in-line inspections being performed. These activities, as discussed below, would result in additional land disturbance and the generation of additional waste.

- **Maximum Allowable Operating Pressure Verification (MAOP):** PHMSA has proposed to require MAOP Verification for a significant number of pipeline miles. See proposed §192.624. According to the PRIA, this would affect over 8,000 miles of transmission lines. PHMSA also expects the majority of these pipelines would be assessed using a combination of ILI and pressure testing. See PRIA Table 3-5, 3-27, 3-34, 3-41. Other assessment methods include pipe replacement and pressure reduction. As discussed below, these assessment methods would result in the generation of a significant amount of waste water, greenhouse gas emissions, and soil disturbance. Because PHMSA has not included MAOP Verification within the Environmental Assessment analysis of the Proposed Rule, the direct environmental impacts of MAOP Verification have not been considered.

- **Hydrostatic Pressure Testing:** PHMSA would require the use of hydrostatic pressure testing in situations involving “legacy” conditions (§192.624(c)(1)) and construction- and manufacturing-defects (§192.917(e)(3)), where pipeline material has quality issues or lost records (§192.935(a)), where fracture mechanics are required (§192.624(d)), and where selective seam cracking is discovered (§192.929(b)(4)). PHMSA’s Environmental Assessment fails to consider this aspect of the Proposed Rule, which would result in significant direct environmental impacts, such as land disturbances, greenhouse gas emissions to purge the pipeline before the hydrostatic pressure test, and the generation of waste water.

- **Alternatives Considered but Dismissed in the Moderate Consequence Area definitions (3.4):** PHMSA describes two alternatives it considered to the definition of MCAs. The first alternative is described as a more limited definition of MCAs using criteria of five buildings intended for human occupancy or five persons/occupied site. However, this “alternative” is actually what is included in the Proposed Rule. See proposed definition of MCA relating to “five (5) or more buildings intended for human occupancy ....” AGA notes that during the White House Office of Management and Budget review process, it appears the referenced number in the MCA definition changed from one to five. It also appears that the Environmental Assessment was not revised to reflect OMB’s revisions. PHMSA describes the second alternative to the MCA definition as restricting the MCA requirements to pipe segments that are greater than or equal to eight inches in diameter. Part of PHMSA’s reasoning for dismissing this alternative is because these pipes would be subject to the MAOP Verification requirements. AGA reminds PHMSA of the differences between integrity management, which is an ongoing process to ensure that pipelines are fit for service, and MAOP Verification, which is a one-time verification of a pipeline’s established MAOP.
Identified Environmental Consequences

PHMSA evaluates the identified topics in the Proposed Rule and generally concludes that the only environmental impact will be that additional testing and inspection requirements will result in increased excavations. PHMSA has underestimated the scope of excavations required by the Proposed Rule and failed to consider the significant amount of waste, both water and soil, that would be generated as a direct result of the increased testing and inspection requirements found in the Proposed Rule. Increased excavations could also impact adjacent wetlands and waters of the U.S. under EPA’s new Clean Water Rule. PHMSA failed to evaluate these potential impacts in its Environmental Assessment. It has also failed to consider the greenhouse gas emissions that will result from the purging of lines prior to hydrostatic testing and when lines need to be removed from service for repair or replacement.120

In addition, AGA notes that as operators evaluate options for complying with aspects of the Proposed Rule, pipelines may be replaced, re-routed, or significantly modified. This could result in the impact of additional land area outside the existing rights of way, which is not considered in PHMSA’s Environmental Assessment.

Excavations

PHMSA concludes that the impacts from excavation would individually have minor localized environmental impacts. AGA generally agrees that excavation associated with natural gas utility projects have minor localized environmental impacts to the immediately surrounding land or water. However, PHMSA has significantly underestimated the expanded number of excavations and the potential size of the excavations that would be required by the Proposed Rule.

Several aspects of the Proposed Rule would require the existing pipelines to be exposed and assessed, where the current regulations allow for continued monitoring of the area or anomaly until actionable levels are reached. See proposed §192.713. The modified repair criteria proposed in the rule would require the class location to be used to determine whether an anomaly requires investigation. See proposed §192.933. Other aspects of the Proposed Rule that would increase the number of excavations, construction and/or pipe replacement including Material Verification, MAOP Determination, Pipeline Assessments outside of HCAs, and corrosion control. As a result of these revisions, the number of excavations would increase as well as their size and the duration since multiple anomalies located on the surrounding joints of pipe may require investigation. The environmental impact of these proposed actions would include expanded excavation areas as well as an increase in the number of excavation areas. It would also result in additional land disturbance and potentially significant increased releases of natural gas to the atmosphere as a result of pipeline segments blow downs to take the pipeline out of service for tie-ins or repairs.

In-line Inspections

PHMSA believes that the majority of pipelines that will require assessments under the Proposed Rule will be completed through the use of in-line inspections, and that many of these pipelines will need to be upgraded for this purpose. See PRIA Table 3-5, 3-27, 3-34, 3-41. PHMSA’s Environmental Assessment fails to consider the waste generated with both upgrading the pipeline to be able to accommodate in-line inspection, as well as the

120 The EA references the potential benefits associated with reduced GHG emissions that could result from the Proposed Rule. The references to the PRIA were not accurate. However, the EA failed to note the emissions associated with blowdowns, an environmental impact that is included in the PRIA.
waste generated from the actual in-line inspection. Prior to undertaking any in-line inspection or upgrading a pipeline to accommodate such inspections, proper cleaning of the pipeline will be required to remove contaminants that could damage in-line inspection tools. The pipelines that generally require the most cleaning are the oldest pipelines – the same pipelines that would require MAOP Verification under the Proposed Rule. This cleaning results in the generation of waste material such as pipeline liquids, mill scale, oil and other debris. On average, each segment of pipe will produce approximately 1,000 to 1,500 gallons of liquid waste, not including wash water. This waste will need to be managed, treated and disposed of in compliance with applicable federal and state environmental laws. Any increase in in-line inspections will necessarily result in an increase in this waste.

**Hydrostatic Pressure Tests**

Hydrostatic testing of pipelines can require a considerable amount of test water. The source of that test water can have environmental impacts. While some small hydrostatic tests might be able to obtain the fill water from public potable water supplies, large and remote hydrostatic tests will require a nearby water source. Water scarcity is a problem in many parts of the country. Because of water withdrawals, many streams and waterbodies may not have the minimum flow rates needed to support aquatic species and riparian ecosystems. The withdrawal of hydrostatic testing fill water could exacerbate those conditions and result in a violation of the federal Endangered Species Act if listed species or critical habitats are present within the fill water source. There may also be state-listed species of concern in some parts of the country under state law. Where local water supplies are insufficient, significant transportation costs will be incurred to truck water in for testing; these costs are not accounted for in the PRIA.

While some small hydrostatic tests might be able to discharge their test waters into a nearby sanitary sewer or into a temporary containment that can be transported to a waste water treatment plant, hydrostatic testing of most lengthy, large diameter, pipelines will require the localized discharge of test waters. The potential contaminants in those discharges could include hydrocarbon liquids and solids, chlorine (if potable fill water is used), and metals.

**Estimation of Benefits**

PHMSA believes that the Proposed Rule will result in fewer accidents and incidents, leading to a reduction in greenhouse gas emissions as well as enhanced protection and safety of pipeline workers and the public. AGA is committed to enhancing safety\(^{121}\) and reducing methane emissions;\(^{122}\) however, AGA believes that PHMSA has significantly overstated the benefits associated with the Proposed Rule. AGA’s comments on the benefits of the Proposed Rule are discussed in more detail in Section V. As PHMSA repeatedly recognizes, natural gas pipelines are already operated at a very safe level and there are only limited “worst-case” scenarios to evaluate any benefits. See 81 Fed. Reg. 20727. In regard to the specific fatality and injury estimates provided in the Environmental Assessment, AGA notes that these values appear to be inconsistent with the values provided in the PRIA (PRIA Table ES-5). Because PHMSA has provided no supporting documentation on how the values in the Environmental Assessment were calculated, stakeholders can provide no meaningful or substantive comments.

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VII. PHMSA’S PROPOSED RULE: SUPPLEMENTARY DOCUMENTS

Comments on Supporting and Related Material

Following the issuance of the Proposed Rule and throughout the comment period, AGA’s efforts have focused on an analysis of PHMSA’s proposed changes to pipeline safety regulations and providing PHMSA with the most meaningful substantive comments within the brief comment period. This analysis has been accomplished in the absence of reasoned justification or technical explanation for many of the proposed changes. The enormity of the Proposed Rule cannot be understated. PHMSA’s proposal represents the most significant revision to the regulation of gas transmission and gathering pipelines since 1970 when PHMSA’s predecessor first developed minimum pipeline safety standards.

Accompanying the Notice of Proposed Rulemaking PHMSA posted multiple documents apparently in an effort to support the Proposed Rule within the docket. These include:

(1) The Initial Regulatory Flexibility Analysis
(2) The Environmental Assessment
(3) A document that identifies the differences between the published Proposed Rule and the Proposed Rule that was sent to OIRA for review
(4) The Preliminary Regulatory Impact Assessment
(5) PHMSA’s report to Congress, Review of Existing Federal and State Regulations for Gas and Hazardous Liquid Gathering Lines
(6) PHMSA’s Proposed Gas Transmission and Gas Gathering Annual Report
(7) PHMSA’s Proposed Gas Transmission and Gas Gathering Incident Report
(8) PHMSA’s Proposed Operator Identification (OPID) Assignment Request Form
(9) PHMSA’s Proposed Reporting-Regulated Natural Gas Gathering Incident Report Form
(10) PHMSA’s report to Congress, Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements.

It should be noted that PHMSA’s report to Congress, Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements, is a 57-page report that was not posted to the docket until June 9, 2016, which was two days after the initial comment period was to close. This left just over thirty days for the public to review a report that was due to Congress prior to PHMSA initiating this rulemaking.

In total, these supporting documents add approximately 400 pages of additional information for public comment to the Proposed Rule. Thoughtful comments to the Proposed Rule, the ten supplemental documents, and additional information provided during PHMSA’s three teleconferences held during the comment period, was simply not feasible. Even with the significant resources expended by AGA and its members, it was not possible to analyze all of the information that was provided during the 90-day comment period. AGA’s silence on these documents does not represent support of the contents within them.
AGA was able to provide an analysis and comments on PHMSA’s Environmental Assessment and Preliminary Regulatory Impact Assessment. As noted in those section comments, there are many errors, inconsistencies, and discrepancies between the changes within the Proposed Rule and the impacts discussed in the Assessment documents. In addition, many of PHMSA’s estimates severely underestimate actual costs experienced by operators and overestimate the benefits. The lack of reasonable assessments impedes the reviewers’ ability to comment on the Proposed Rule and its impacts.

In a cursory review of the accompanying incident and annual reporting forms, AGA notes that the changes are impactful and require a detailed analysis. Unfortunately, it was not reasonable to expect AGA or any stakeholder to do so in the timeframe given. Given more time, AGA would have provided meaningful comments that analyzed the merit of the proposed changes, identified potential issues with the new reporting requirements, and quantified the burden of these changes.

It was also not possible to review the reports to Congress that were posted. AGA is disturbed that the report, *Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements*, was provided at such a late date, when ideally it would have been provided prior to this rulemaking. As noted above, this report was meant to provide valid information to Congress on the necessity of portions of the Proposed Rule. Without providing the public an opportunity to review this report and provide comments, PHMSA proceeded with the rulemaking.

If the reports had been provided outside this rulemaking or adequate time would have been provided AGA would have been able to offer a thorough analysis of the supplemental documents and supplied meaningful comments. AGA’s inability to do this is simply due to the magnitude of the Proposed Regulation, the quantity of the information within the supporting documents, and the very limited time provided for comments.

**VIII. CONCLUSION**

AGA commends PHMSA’s continuing commitment to pipeline safety and appreciates the opportunity to comment on the PHMSA Safety of Gas Transmission and Gathering Lines Proposed Rule. Safety is AGA’s number one priority and commitment.

AGA recognizes the challenges associated with developing a comprehensive regulation that would address such a variety of topics and commends PHMSA on its effort. AGA supports the intended pipeline safety benefits behind many of the modifications to pipeline safety regulations in PHMSA’s Proposed Rule. Many of the topics within the Proposed Rule have been the source of significant discussion and debate among stakeholders in recent years. However, PHMSA’s proposal fails to consider the extensive existing regulatory and voluntary safety initiatives in place and imposes prescriptive and burdensome requirements on operators that, in the end, will likely not address the perceived regulatory pipeline safety benefits. PHMSA has failed to provide the type of reasoned justification or explanation necessary to support such an onerous rulemaking, or to consider the limits of its authority in prescribing minimum safety standards.
AGA’s remains committed to working with PHMSA to address its concerns to the Proposed Rule, to meet the Congressional mandates within the Pipeline Safety Act of 2011, and to expand integrity management principles beyond high consequence areas and looks forward to future conversations.

Respectfully submitted,

Date: July 7, 2016

By:

Christina Sames

For further information, please contact:

Christina Sames
Vice President
Operations and Engineering
American Gas Association
400 North Capitol Street, NW
Washington, D.C. 20001
(202) 824-7214
csames@aga.org

Erin Kurilla
Director
Operations & Engineering Services
American Gas Association
400 North Capitol Street, NW
Washington, D.C. 20001
(202) 824-7328
ekurilla@aga.org
§191.23 Reporting safety-related conditions.

(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with §191.25 the existence of any of the following safety-related conditions involving facilities in service:

1. In the case of a pipeline (other than an LNG facility) that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result.

2. Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline or the structural integrity or reliability of an LNG facility that contains, controls, or processes gas or LNG.

3. Any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes gas or LNG.

4. Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength.

5. Any malfunction or operating error that causes the pressure of a distribution, Type A, or Type B gathering pipeline or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the margin (build-up) allowed for operation of pressure limiting or control devices.

6. A leak in a pipeline or LNG facility that contains or processes gas or LNG that constitutes an emergency.

7. Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank.

8. Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline or an LNG facility that contains or processes gas or LNG.

9. For transmission pipelines, each exceedance of the maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in §§192.201, 192.620(e), and 192.739, as applicable.

(b) A report is not required for any safety-related condition that—

1. Exists on a master meter system or a customer-owned service line;

2. Is an incident or results in an incident before the deadline for filing the safety-related condition report;

3. Exists on a pipeline (other than an LNG facility) that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or

4. Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions...
under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline and any condition under paragraph (a)(9) of this section.

PART 192 – TRANSPORTATION OF NATURAL ANOTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

Subpart A - General

§ 192.3 Definitions

*Distribution center* means the initial point where gas volumes are either metered or have pressure of volume enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale, for example:

1. at a metering location
2. pressure reduction location, or
3. where there is a reduction prior to delivery to customers through a distribution line in the volume of gas, such as a lateral off a transmission line.

*Dry gas or dry natural gas* means gas with less than 7 pounds of water per million (MM) cubic feet and not typically subject to excessive upsets allowing electrolytes into the gas stream.

[DELETE OR....]

*Legacy transmission construction techniques* mean usage of any historic, now-abandoned, construction practice to construct or repair transmission pipe segments no longer recognized as acceptable for new construction or repairs under this Part, including any of the following techniques:

1. Wrinkle bends that are not allowable under §192.315;
2. Miter joints exceeding three degrees that are not allowable under §192.233;
3. Dresser couplings; Mechanical Fittings without restraining elements
4. Non-standard fittings or field fabricated fittings (e.g., orange-peeled reducers) with unknown pressure ratings Fittings that do not adhere with §192.153.
5. Acetylene welds; or
6. Bell and spigots; or
7. Puddle welds.

[DELETE OR....]

*Legacy transmission pipe* means steel transmission pipe with a longitudinal joint factor, as defined in §192.113, less than 1.0, or was manufactured by a process no longer accepted by industry standards: using any of the following techniques, regardless of the date of manufacture:

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

**Moderate consequence area** means an onshore area established by one of the methods described in paragraphs (1) or (2) as follows for pipelines operating at greater than 30% SMYS:

(1) An area classified as –
   (i) A Class 2 location under §192.5; or
   (ii) A Class 1 location that is within a potential impact circle, as defined in §192.903 containing the existing edge of pavement for a designated interstate, freeway, or expressway, and other principal arterial roadway of 4-lanes or more as defined in the Federal Highway Administration’s *Highway Functional Classification Concepts, Criteria, and Procedures*.
   (iii) Does not meet the definition of high consequence area as defined §192.903.

(2) The area that is within a potential impact circle, as defined in §192.903, containing –
   (i) five (5) or more buildings intended for human occupancy; or
   (ii) An outside area or open structure that is occupied by five (5) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive). Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility, or
   (iii) an occupied site a non-residential building intended for human occupancy that is occupied by less than twenty persons five (5) or more persons at least five (5) days a week for ten (10) weeks in any twelve (12) – month period. (The days and weeks need not be consecutive). Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or
   (iv) a right-of-way The existing edge of pavement for a designated interstate, freeway, or expressway, and other principal 4-lane arterial roadway of 4-lanes or more as defined in the Federal Highway Administration’s *Highway Functional Classification Concepts, Criteria and Procedures*.
   (v) Does not meet the definition of high consequence area as defined in §192.903.

(3) Where a potential impact circle is calculated under method (1) or (2) to establish a moderate consequence area, the length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an occupied site a non-residential building intended for human occupancy that is occupied by less than twenty persons five (5) or more persons at least five (5) days a week for ten (10) weeks in any twelve (12) – month period, five (5) ten (10) or more buildings intended for human occupancy, or a right-of-way the existing edge of pavement for a designated interstate, freeway, or expressway, or other principal 4-lane arterial roadway of 4-lanes or more, to the outermost edge of the last contiguous potential impact circle that contains either an occupied site a non-residential building intended for human occupancy that is occupied by less than twenty persons five (5) or more persons at least five (5) days a week for ten (10) weeks in any 12-month period, five (5) or more buildings intended for human occupancy, or a right-of-way existing edge of pavement for a designated interstate, freeway, or expressway, or other principal 4-lane arterial roadway of 4-lanes or more as defined in the Federal Highway Administration’s *Highway Functional Classification Concepts, Criteria, and Procedures*.
Pipelines that can accommodate inspection by means of instrumented inspection tool means a length of pipeline through which a free-swimming, commercially available ILI tool can travel (using flow and pressure conditions encountered in normal operations), inspect the entire circumference of the pipe, capture and record or transmit relevant, interpretable inspection data in sufficient detail for further evaluation of anomalies without the need for additional permanent physical modifications to the pipeline.

Traceable, verifiable, and complete means that a single quality record, or a combination of records, related to the maximum allowable operating pressure of a gas transmission pipeline:

1. can be clearly linked to information about a pipeline segment or facility and is finalized as evidenced by a signature, date, or other appropriate marking or
2. has other similar characteristics that support its validity.

A single quality record can be traceable, verifiable, and complete. However, in some situations, complementary, but separate, documentation may be necessary. In determining whether a record is traceable, verifiable, and complete, due consideration shall be given to the standards and practices in effect at the time the record was created.

Transmission line means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility field to a distribution center, storage facility field, or large volume customer that is not down-stream from a distribution center; (2) has a MAOP operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field; or (4) is voluntarily determined by the operator to be a transmission line. Note: A large volume customer (factories, power plants, and institutional users of gas) may receive similar volumes of gas as a distribution center.

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


§192.9 What requirements apply to gathering lines?

(a) Requirements. An operator of a gathering line must follow the safety requirements of this part as prescribed by this section.

(b) Offshore lines. An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §192.150 and in subpart O of this part.

(c) Type A lines, Area 1 Lines. An operator of a Type A, Area 1 regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§192.13(d) and (e), 192.67, 192.127, 192.150, 192.205, 192.227(c), 192.285(c), 192.319, 192.461(f), 192.465(f), 192.473(c), 192.478, 192.485(d), 192.607, 192.613, 192.624, 192.711(b)(1), 192.710, 192.713, [or AGA’s proposed Subpart Q] and in subpart O of this part. However, an operator of a Type A, Area 1 regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.
(d) Type A, Area 2 and Type B lines. An operator of a Type A, Area 2 or Type B regulated onshore gathering line must comply with the following requirements:

1. If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines, except the requirements in §§192.13(d) and (e), 192.67, 192.127, 192.150, 192.205, 192.227(c), 192.285(c), 192.319, 192.461(f), 192.465(f), 192.473(c), 192.478, 192.485(d), 192.607, 192.613, 192.624, 192.711(b)(1), 192.710, 192.713, [or AGA’s proposed Subpart Q] and in subpart O of this part;
2. If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except the requirements of §§192.461(f), 192.465(f), 192.473(c), 192.478, and 192.485(d);
3. Carry out a damage prevention program under §192.614;
4. Establish a public education program under §192.616;
5. Establish the MAOP of the line under §192.619; and
6. Install and maintain line markers according to the requirements for transmission lines in §192.707.
7. Conduct leakage surveys in accordance with §192.706 using leak detection equipment and promptly repair hazardous leaks that are discovered in accordance with §192.703(c); and
8. For Type A, Area 2 regulated on shore gathering line only, develop procedures, training, notifications, emergency plans and implement as described in §192.615.

(e) If a regulated onshore gathering line existing on [insert the effective date of the rule] was not previously subject to this part, an operator has until [insert date two years after effective date of the rule] to comply with the applicable requirements of this section, unless the Administrator finds a later deadline is justified in a particular case.

(f) If, after [insert the effective date of the rule], a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has one year for Type A, Area 2 and Type B lines and two years for Type A, area 1 lines after the line becomes a regulated onshore gathering line to comply with this section.

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

(a) No person may operate a segment of pipeline listed in the first column that is readied for service after the date in the second column, unless:
(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or
(2) The pipeline qualifies for use under this part according to the requirements in §192.14.

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore gathering line</td>
<td></td>
</tr>
<tr>
<td></td>
<td>July</td>
</tr>
<tr>
<td></td>
<td>31,</td>
</tr>
<tr>
<td></td>
<td>1977.</td>
</tr>
<tr>
<td>Regulated onshore gathering line to which this part did not apply until April 14, 2006</td>
<td>March</td>
</tr>
<tr>
<td></td>
<td>15</td>
</tr>
<tr>
<td></td>
<td>2007.</td>
</tr>
</tbody>
</table>
Regulated onshore gathering line to which this part did not apply until \(\text{(insert effective date of the rule)}\)

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore gathering line</td>
<td>July 31, 1977.</td>
</tr>
<tr>
<td>Regulated onshore gathering line to which this part did not apply until April 14, 2006</td>
<td>March 15, 2007.</td>
</tr>
<tr>
<td>Regulated onshore gathering line to which this part did not apply until (\text{(insert effective date of the rule)})</td>
<td>(\text{(insert effective date of the rule plus one two years)}).</td>
</tr>
<tr>
<td>All other pipelines</td>
<td>November 12, 1970.</td>
</tr>
</tbody>
</table>

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

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

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

(d) Each operator must make and retain records that demonstrate compliance with the explicit record keeping requirements of this part.

a. Operators of transmission pipelines must keep records for the retention period specified in Appendix A.

(3) For gas transmission pipelines installed after [insert date that is one year after the effective date of the rule], maximum allowable operating pressure records must be reliable, traceable, verifiable, and complete.
(4) *Traceable, verifiable, and complete* means that a single quality record, or a combination of records, related to the maximum allowable operating pressure of a gas transmission pipeline:

   (iv) can be clearly linked to information about a pipeline segment or facility and is finalized as evidenced by a signature, date, or other appropriate marking, or
   
   (v) has other similar characteristics that support its validity.

   (vi) A single quality record can be traceable, verifiable, and complete. However, in some situations, complementary, but separate, documentation may be necessary. In determining whether a record is traceable, verifiable, and complete, due consideration shall be given to the standards and practices in effect at the time the record was created.

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

**Subpart B – Materials**

§192.67 Records: Materials.

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

**Subpart C – Pipe Design**

§ 192.127 Records: Pipe design.

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

**Subpart D – Design of Pipe Components**

§192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices, in accordance with the requirements and recommendations in NACE SP0102-2010, Section 7 (incorporated by reference, see §192.7)

§192.205 Records: Pipeline Components.

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

Subpart E – Welding of Steel in Pipelines

§192.227 Qualification of welders and welding operators.

(a) Except as provided in paragraph (b) of this section, each welder or welding operator must be qualified in accordance with section 6, section 12, or Appendix A of API Std 1104 (incorporated by reference, see §192.7), or section IX of ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, see §192.7). However, a welder or welding operator qualified under an earlier edition than the edition listed in §192.7 may weld but may not re-qualify under that earlier edition.

(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.

(c) Records for transmission pipelines installed after [insert effective date of rule] demonstrating each individual welder qualification at the time of pipeline installation in accordance with this section must be retained for the life of the pipeline.

Subpart F – Joining of Materials Other Than by Welding


(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and
(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and
(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under §192.283(a) applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is:

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.
(c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under §192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator’s system is qualified in accordance with this section.

(e) For transmission pipelines installed after [insert effective date of rule], records demonstrating plastic pipe joining qualifications at the time of pipeline installation in accordance with this section must be retained for the life of the pipeline.

Subpart G – General Construction Requirements for Transmission Lines

§192.319 Installation of pipe in a ditch.

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that:
   (3) Provides firm support under the pipe; and
   (4) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(c) All offshore pipe in water at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water must be installed so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.

(d) Promptly after a ditch for a steel onshore transmission line is backfilled, but not later than three twelve months after placing the pipeline in service, the operator must perform an assessment to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG) or other coating assessment technique allowed by section 4 of NACE SP0502 (incorporated by reference, see § 192.7). The operator must repair any coating damage classified as moderate or severe (voltage drop greater than 35% for DCVG or 50 dBμv for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six twelve months of the assessment. Each operator of transmission pipelines must make and retain for the life of the pipeline records documenting the coating assessment findings and repairs.

Subpart I – Requirements for Corrosion Control

§192.461 External corrosion control: Protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must—
   (1) Be applied on a properly prepared surface;
   (2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;
   (3) Be sufficiently ductile to resist cracking;
   (4) Have sufficient strength to resist damage due to handling (including but not limited to transportation, installation, boring, and backfilling) and soil stress; and
(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.

(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

(f) Promptly, but no later than three twelve months after backfill of an onshore transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), conduct surveys to assess any coating damage to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG), or other coating assessment technique allowed by section 4 of NACE SP0502 (incorporated by reference, see § 192.7). Remediate any coating damage classified as moderate or severe (voltage drop greater than 35% for DCVG or 50 dBμv for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six twelve months of the assessment.

§192.465 External corrosion control: Monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2½ months, to insure that it is operating.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Operators shall take prompt remedial action to correct any deficiencies indicated by the inspection and testing provided in paragraphs (a), (b) and (c) of this section. Remedial action must be initiated completed promptly, but no later than the next monitoring interval in §192.465 or within one year, whichever is less by the next monitoring interval, but no later than one year, whichever is less.

(e) After the initial evaluation required by §§192.455(b) and (c) and 192.457(b), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
(f) For onshore transmission lines, where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in Appendix D of this part, the operator must determine the extent of the area with inadequate cathodic protection. Close interval surveys must be conducted in both directions from the test station with a low cathodic protection (CP) reading at a minimum of approximately five-foot intervals. Close interval surveys must be conducted, where practical based upon geographical, technical, or safety reasons. Close interval surveys required by this part must be completed with the protective current interrupted unless it is impractical to do so for technical or safety reasons. Remediation of areas with insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline must be performed in accordance with paragraph (d). The operator must confirm restoration of adequate cathodic protection by close interval survey over the entire area.

§192.473 External corrosion control: Interference currents.

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

(c) For onshore gas transmission pipelines, the program required by paragraph (a) must include:

(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be taken on a periodic basis including, when there is knowledge of current flow increases over pipeline segment grounding design, from any co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures;

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could impact the effectiveness of cathodic protection; and

(3) Implementation of remedial actions to protect the pipeline segment from detrimental interference currents. promptly but no later than six months after completion of the survey. If the remedial action cannot be completed within twelve months, the operator shall document actions in progress to correct the interference and the expected timeframe for completion.

§192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

(a) For onshore transmission pipelines, each operator must develop and implement a monitoring and mitigation program to identify any potentially corrosive constituents in the gas being transported and mitigate any corrosive effects. Potentially corrosive constituents include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and free water, either by itself or in combination. Each operator must evaluate the partial pressure of each corrosive constituent by itself or in combination to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures.

(b) The monitoring and mitigation program in paragraph (a) of this section must include:

(1) At points where gas with potentially corrosive contaminants can enters the pipeline, The use of equipment methods to determine the corrosive gas stream constituents at points where gas with potentially corrosive contaminants enters the pipeline.

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(2) Product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate the potentially corrosive gas stream constituents;

(3) Evaluation twice each calendar year, at intervals not to exceed 7½ months, of gas stream and liquid quality samples and implementation of adjustments and mitigative measures to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

(c) If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked at least twice each calendar year, at intervals not exceeding 7 ½ months.

(d) Each operator must review its monitoring and mitigation program based on operators O&M Manual or at least twice once each calendar year, at intervals not to exceed 7 ½ 15 months. based on the results of its gas stream sampling and internal corrosion monitoring in (a) and (b) and implement adjustments in its monitoring for and mitigation of the potential for internal corrosion due to the presence of potentially corrosive gas stream constituents.

§192.485 Remedial measures: Transmission lines.

(a) General corrosion. Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) Localized corrosion pitting. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, see §192.7) or the procedure in PRCI PR 3-805 (R-STRENG) (incorporated by reference, see §192.7) for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the procedures, including the appropriate use of class location and pipe longitudinal seam factors in pressure calculations for pipe defects. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, and crack-related defects, appropriate failure criteria must be used and justification of the criteria must be documented.

(d) Pipe and material properties used in remaining strength calculations and the pressure calculations made under this paragraph must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgments may be used.

§ 192.493 In-line inspection of pipelines
When conducting in-line inspection of pipelines required by this part, each operator must comply with the requirements and recommendations of API STD 1163, *In-line Inspection Systems Qualification Standard*, except for Section 11, Quality Management System; ANSI/ASNT ILI-PQ-2005, *In-line Inspection Personnel Qualification and Certification*; and NACE SP0102-2010, *In-line Inspection of Pipelines* (incorporated by reference, see § 192.7). Assessments may also be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102-2010, provided they comply with those sections of NACE SP0102-2010 that are applicable.

**Subpart J – Test Requirements**

**§192.506 Transmission lines: Spike hydrostatic pressure test for existing steel pipe with integrity threats.**

(a) Each segment of an existing steel pipeline that is operated at a hoop stress level of 30% of specified minimum yield strength or more and is required to be spike tested in §192.624, §192.710 [or §192.1109], §192.921, §192.937. has been found to have integrity threats that cannot be addressed by other means such as in-line inspection or direct assessment must be strength tested by a spike hydrostatic pressure test in accordance with this section to substantiate the proposed maximum allowable operating pressure.

(b) The spike hydrostatic pressure test must use water as the test medium.

(b) The baseline test pressure without the additional spike test pressure is the test pressure specified in §§ 192.619(a)(2), 192.620(a)(2), or 192.624, whichever applies.

(c) The test must be conducted by maintaining the pressure at or above the baseline test pressure for at least 8 hours as specified in § 192.505(e).

(d) After the test pressure stabilizes at the baseline pressure and within the first two hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.50 times MAOP or 105% SMYS. This spike hydrostatic pressure test must be held for at least 10 minutes.

(e) If the integrity threat being addressed by the spike test is of a time-dependent nature such as a cracking threat, the operator must establish an appropriate retest interval and conduct periodic retests at that interval using the same spike test pressure. The appropriate retest interval and periodic tests for the time-dependent threat must be determined in accordance with the methodology in § 192.624(d).

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

(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;

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

(3) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;
(4) Assessment techniques and acceptance criteria;
(5) Remediation methods for assessment findings;
(6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;
(7) Procedures for remaining crack growth analysis and pipe segment life analysis for the time interval for additional assessments, as required; and
(8) Evidence of a review of all procedures and assessments by a subject matter expert(s) in both metallurgy and fracture mechanics

Subpart L - Operations

§ 192.607 Verification of Pipeline Material: Onshore steel transmission pipelines.

(a) Applicable Locations. Each operator must follow the requirements of paragraphs (b) through (d) of this section for each segment of onshore, steel, gas transmission pipeline installed before [insert the effective date of the rule] that does not have reliable, traceable, verifiable, and complete material documentation records for line pipe, valves, flanges, and components and meets any of the following conditions:

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

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

(c) Material Documentation. Each operator must have reliable, traceable, verifiable, and complete records documenting the material documentation records for line pipe, valves, flanges, and components to establish MAOP where supportable, sound engineering judgments cannot be made, including:

(1) For line pipe and fittings, records must document diameter, wall thickness, specified minimum yield strength, grade (yield strength and ultimate tensile strength), chemical composition, and pipe class for longitudinal joint factor determination, per §192.113 seam type, coating type, and manufacturing specification.

(2) For valves, records must document either one of the following: the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating and grade. For valves with pipe weld ends, records must document the valve material grade and weld end bevel condition to ensure compatibility with pipe end conditions;

(3) For flanges, records must document either one of the following: the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating and grade, and the material grade and weld end bevel condition to ensure compatibility with pipe end conditions;

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

(d) Verification of Material Properties. For any material documentation records for line pipe, valves, flanges, and components specified in paragraph (c) of this section that are not available, the operator must take the following actions to determine and verify the physical characteristics. While the operator is performing these actions, supportable, sound engineering judgments are permitted to be utilized.

(1) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for line pipe at all above ground locations.
(2) Develop and implement procedures for conducting destructive tests, examinations, and assessments for buried line pipe at all excavations associated with replacements or relocations of pipe segments that are removed from service.

(3) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for buried line pipe at all excavations associated with anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, or any other reason for which the pipe segment is exposed, except for segments exposed during excavation activities that are in compliance with §192.614, until completion of the minimum number of excavations as follows.

(i) The operator must define each pipeline population with an undocumented or inadequately documented pipeline segment attribute required for MAOP determination and remaining strength calculations. For each unique combination of the following attributes: wall thicknesses (within 10 percent of the smallest wall thickness in the population), grade, manufacturing process, pipe manufacturing dates (within a two year interval) and construction dates (within a two year interval).

(ii) For each pipeline population identified according to (i) above, the minimum number of excavations at which line pipe must be tested to verify pipeline material properties is determined in accordance with either the lesser of the following (A) or (B).

(A) The lesser of (1) or (2); or
   i. 150 excavations; or
   ii. If the segment is less than 150 miles, a number of excavations equal to the population’s pipeline mileage (i.e., one set of properties per mile), rounded up to the nearest whole number. The mileage for this calculation is the cumulative mileage of pipeline segments in the population without reliable, traceable, verifiable, and complete material documentation.
   iii. Assessments must be proportionally spaced throughout the pipeline segment. Each length of the pipeline segment equal to 10 percent of the total length must contain 10 percent of the total number of required excavations, e.g. a 200 mile population would require 15 excavations for each 20 miles.

(B) Alternatively, an operator may determine the number of excavations through statistical analysis.

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

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

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

(vi) For non-destructive tests, at each test location, a set of material properties tests must be conducted in accordance with the number appropriate to achieve the accuracy requirements established in (iv) above in accordance with a qualified testing procedure at a minimum of five places in each circumferential quadrant of the pipe for a minimum total of 20 test readings at each pipe cylinder location.

(vii) For destructive tests, at each test location, a set of materials properties tests must be conducted in accordance with an applicable manufacturing specification. On each circumferential quadrant of a test pipe cylinder removed from each location, for a minimum total of four tests at each location.

(viii) If the results of all tests conducted in accordance with paragraphs (i) and (ii) verify that unknown material properties are consistent with all available information on each population pipeline or are more conservative than current assumptions (such as: thicker walled pipe, smaller diameter, or higher grade), then no additional excavations are necessary. However, if the test results identify line pipe with properties that are not consistent as conservative as the current with existing assumptions expectations based on all available information for each population pipeline, then the operator must modify their Material Documentation Program testing frequency to address these inconsistencies. Perform tests at additional excavations. The minimum number of excavations that must be tested depends on the number of inconsistencies observed between as-found tests and available operator records, in accordance with the table below:

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

(ix) The tests conducted for a single excavation according to the requirements of §192.607(d)(3)(iii) through (vii) above count as one sample under the sampling requirements of §192.607(d)(3)(i), (ii), and (viii).
In the event that an operator determines another technology, such as in-line inspection, is capable of meeting the confidence levels specified in §192.607(d)(3)(iv), the Material Documentation Plan should be revised to reflect the use of this other technology. The technology must still be able to capture a statistically significant quantity of data for each pipeline for which material verification is being performed.

(4) For mainline pipeline components other than line pipe, the operator must develop and implement procedures for establishing and documenting one of the following: the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating, the ANSI rating and material grade (to assure compatibility with pipe ends).

(xi) Materials in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, operator piping, or cross-connections with isolation valves from the mainline pipeline are not required to be tested for chemical and mechanical properties.

(xii) Verification of mainline material properties is required for non-line pipe components, including but not limited to, valves, flanges, fittings, fabricated assemblies, and other pressure retaining components appurtenances that are:

(A) 2-inch nominal diameter and larger, or
(B) Material grades greater than 42,000 psi (X-42), or
(C) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

(xiii) Procedures for establishing material properties for non-line pipe components where records are inadequate must be based upon documented manufacturing specifications. Where specifications are not known, usage of manufacturer’s stamped or tagged material pressure ratings and material type may be used to establish pressure rating. The operator must document the basis of the material properties established using such procedures.

(5) The material properties determined from the destructive or non-destructive tests required by this section cannot be used to raise the original grade or specification of the material, unless the current MAOP is unknown and is based on an assumed yield strength of 24 ksi in accordance with §192.107(b)(2), which must be based upon the applicable standard referenced in §192.7.

(6) If conditions make material verification by the above methods impracticable or if the operator chooses to use “other technology” or “new technology” (alternative technical evaluation process plan), the operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph § 192.624(e) of this section. The operator must submit the alternative technical evaluation process plan to the Associate Administrator of Pipeline Safety with the notification and must obtain a “no objection letter” from the Associate Administrator of Pipeline Safety prior to usage of an alternative evaluation process.

§192.613 Continuing surveillance.

(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with §192.619 (a) and (b).
(c) Following an extreme weather event such as a hurricane or flood, an earthquake, landslide, a natural disaster, or other similar event, which in the operator’s judgment has the likelihood of damage to infrastructure, an operator must inspect patrol pipeline right-of-ways and above ground facilities of all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

(1) Patrol inspection method. An operator must consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial patrol inspection to determine damage and the need for the additional assessments required under the introductory text of paragraph (c) in this section.

(2) Time period. The patrol inspection required under the introductory text of paragraph (c) of this section must commence within 72 hours after the cessation of the event, defined as the point in time should commence as soon as practicable considering when the affected area can be safely accessed by the personnel and equipment, taking into account the availability of personnel and equipment, required to perform the patrol inspection as determined under paragraph (c)(1) of this section, whichever is sooner.

(3) Remedial action. An operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the patrol inspection required under the introductory paragraph (c) in this section. Such actions might include, but are not limited to:

   (i) Reducing the operating pressure or shutting down the pipeline;
   (ii) Modifying, repairing, or replacing any damaged pipeline facilities;
   (iii) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;
   (iv) Performing additional patrols, surveys, tests, or inspections;
   (v) Implementing emergency response activities with Federal, State, or local personnel; or
   (vi) Notifying affected communities of the steps that can be taken to ensure public safety.

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

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

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

      (i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, see §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or
      (ii) If the pipe is 12\(\frac{3}{4}\) inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

   (2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

      (i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.
(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

<table>
<thead>
<tr>
<th>Class</th>
<th>Location</th>
<th>Factors¹, segment—</th>
<th>Converted under §192.14</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>before (Nov. 12, 1970)</td>
<td>Installed (Nov. 11, 1970) and before (Date of New Rule)</td>
<td>Installed after (Date of New Rule – 1 Day)</td>
</tr>
<tr>
<td>1</td>
<td>1.1</td>
<td>1.1</td>
<td>1.25</td>
</tr>
<tr>
<td>2</td>
<td>1.25</td>
<td>1.25</td>
<td>1.25</td>
</tr>
<tr>
<td>3</td>
<td>1.4</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td>4</td>
<td>1.4</td>
<td>1.5</td>
<td>1.5</td>
</tr>
</tbody>
</table>

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

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

<table>
<thead>
<tr>
<th>Pipeline segment</th>
<th>Pressure date</th>
<th>Test date</th>
</tr>
</thead>
<tbody>
<tr>
<td>—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006 but before (insert effective date of the rule)</td>
<td>March 15, 2006, or date line becomes subject to this part, whichever is later</td>
<td>5 years preceding applicable date in second column.</td>
</tr>
<tr>
<td>—Onshore gathering line that first became subject to this part (other than §192.612) on or after (insert effective date of the rule)</td>
<td>(Insert date that is one year after the effective date of the rule), or date line becomes subject to this part, whichever is later.</td>
<td></td>
</tr>
<tr>
<td>—Onshore transmission line that was a gathering line not subject to this part before March 15, 2006</td>
<td>March 15, 2006, or date line becomes subject to this part, whichever is later.</td>
<td></td>
</tr>
<tr>
<td>Offshore gathering lines</td>
<td>July 1, 1976</td>
<td>July 1, 1971.</td>
</tr>
</tbody>
</table>
(4) The pressure determined by the operator to be the maximum safe pressure after considering, material records including material properties identified in accordance with §192.607, and the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

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

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

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

1. Method 1: Pressure Test — Pressure test in accordance with §192.624(c)(1)(i) or spike hydrostatic pressure test in accordance with §192.624(c)(1)(ii), as applicable;
2. Method 2: Pressure Reduction — Reduction in pipeline maximum allowable operating pressure in accordance with §192.624(c)(2);
3. Method 3: Engineering Critical Assessment — Engineering assessment and analysis activities in accordance with §192.624(c)(3);
4. Method 4: Pipe Replacement — Replacement of the pipeline segment in accordance with §192.624(c)(4);
5. Method 5: Pressure Reduction for Segments with Small PIR and Diameter — Reduction of maximum allowable operating pressure and other preventive measures for pipeline segments with small PIRs and diameters, in accordance with §192.624(c)(5); or

(e) For onshore steel transmission pipelines installed after [one year after effective date of rule], operators must maintain all records necessary to establish and document the established MAOP of each pipeline as long as the pipe or pipeline remains in service. Records that may establish the pipeline MAOP, include, but are not limited to, design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type and other related data. For onshore steel transmission pipeline installed after [one year after effective date of rule], records used to document the established MAOP must be reliable, traceable, verifiable, and complete.

§192.624 Maximum allowable operating pressure verification: Onshore steel transmission pipelines.
(a) Applicable Locations

All other pipelines | July 1, 1970 | July 1, 1965.
The pipeline segment has experienced a reportable in-service incident as defined in §191.3 since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations:

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

For pipelines not relying on 192.619(c) to determine MAOP, pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment are incomplete or unavailable, including, but not limited to, records required by §192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline is located in one of the following locations:

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

The pipeline segment maximum allowable operating pressure was established in accordance with §192.619(c) of this subpart before [insert effective date of rule], operates at greater than 30% SMYS and is located in one of the following locations:

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

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

(1) The operator must develop and document a plan for completion of all actions required by this section by [insert date that is 1 year after the effective date of rule].

(2) The operator must complete all actions required by this section on at least 50% of the mileage of locations pipeline segments that meet the conditions of §192.624(a) by [insert date that is 8 10 years after the effective date of rule].

(3) The operator must complete all actions required by this section on 100% of the mileage of locations pipeline segments that meet the conditions of §192.624(a) by [insert date that is 15 20 years after the effective date of rule].

(4) If operational and environmental constraints limit the operator from meeting the deadlines in §192.614 (b)(2) and (3) above, the operator may petition for an extension of the completion deadlines by up to one year, upon submittal of a notification to the Associate Administrator of the Office of Pipeline Safety in accordance with paragraph (e). The notification must include an up-to-date plan for completing all actions in accordance with (b)(1), the reason for the requested extension, current status, proposed completion date, remediation activities outstanding, and any needed temporary safety measures to mitigate the impact on safety.

(c) Maximum Allowable Operating Pressure Determination-Verification. The operator of a pipeline segment meeting the criteria in paragraph (a) above must establish verify its maximum allowable operating pressure using one of the following methods:

(1) Method 1: Pressure test.
(i) Perform a pressure test in accordance with §192.505(c) Subpart J of this Part. The maximum allowable operating pressure will be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or §192.620(a)(2)(ii).

(ii) If the pipeline segment includes legacy pipe or was constructed using legacy construction techniques or the pipeline-pipe with a longitudinal joint factor less than 1.0, as defined in §192.113, was manufactured by a process no longer accepted by industry standards, was constructed using construction techniques or practices no longer acceptable for new construction under part 192, has experienced an incident, as defined by §191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking, that was not otherwise addressed by the operator, then the operator must perform a spike pressure test in accordance with §192.506. The maximum allowable operating pressure will be equal to the test pressure specified in §192.506(c) divided by the greater of 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or §192.620(a)(2)(ii).

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

(2) Method 2: Pressure Reduction - The pipeline maximum allowable operating pressure will be no greater than the pressure described in §192.620(c)(2)(i). highest actual operating pressure sustained by the pipeline during the 18 months preceding [insert effective date of rule]...The value used as the highest actual sustained operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest pressure value for the entire segment or using the operating pressure gradient (i.e., the location-specific operating pressure at each location).

(i) Baseline pressure determination:

   (A) For pipelines that have experienced a reportable in-service incident due to an original manufacturing-related defect, a construction-, installation- or fabrication-related defect the pipeline maximum allowable operating pressure will be no greater than the actual operating pressure at the time of the reportable in-service incident divided by the greater of 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or §192.620(a)(2)(ii).

   (B) For pipelines that meet the applicability of §192.624(a)(2) and §192.624(a)(3) the pipeline maximum allowable operating pressure will be no greater than the highest documented operating pressure sustained by the pipeline divided by 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or §192.620(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period.

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

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

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

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

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

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

(A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in §192.624(c)(2);

(B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with paragraph (d) of this section;

(C) Justification that establishing maximum allowable operating pressure by another method allowed by this section is impractical;

(D) Justification that the reduced maximum allowable operating pressure determined by the operator is safe based on analysis of the condition of the pipeline segment, including material records, material properties verified in accordance §192.607, and the history of the segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned.

(E) Planned duration for operating at the requested maximum allowable operating pressure, long term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts in metallurgy and fracture mechanics.

(vi) Any reductions in MAOP voluntarily initiated by the operator from December 31, 2003 until the date that the operator elects to verify MAOP using Method 2 shall be considered as a Pressure Reduction conducted under §192.624(c)(2).

(3) Method 3: Engineering Critical Assessment

[Note: See INGAA’s Comments]

(4) Method 4: Pipeline Replacement – Replace the pipeline segment.

(5) Method 5: Pressure Reduction for Segments with Small Potential Impact Radius and Diameter – Pipelines with a maximum allowable operating pressure less than 30 percent of specified minimum yield strength, a potential impact radius (PIR) less than or equal to 200 feet, nominal diameter equal to or less than 8-inches, and which cannot be assessed using inline inspection or pressure test, may establish the maximum allowable operating pressure as follows: performing the actions in either (i) or (ii) as listed below:
Reduce the pipeline maximum allowable operating pressure to no greater than the pressure described in §192.624(c)(5)(i)(A), (B), or (C). during 18 months preceding [insert effective date of rule]. The reduced maximum allowable operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire segment or the operating pressure gradient (i.e., the location-specific operating pressure at each location).

(A) For pipelines that have experienced a reportable in-service incident due to an original manufacturing-related defect, a construction-, installation- or fabrication-related defect the pipeline maximum allowable operating pressure will be no greater than the actual operating pressure at the time of the reportable in-service incident divided by 1.1.

(B) For pipelines that meet the applicability of §192.624(a)(2) and §192.624(a)(3) the pipeline maximum allowable operating pressure will be no greater than the highest documented operating pressure sustained by the pipeline divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of eight hours during one continuous 30-day period.

(C) Any reductions in MAOP voluntarily initiated by the operator from December 31, 2003 until the date that the operator elects to verify MAOP using Method 2 shall be considered as a Pressure Reduction initiated under 192.624(c)(5); or

Perform the following additional actions to ensure the safety of the pipeline.

(A) Conduct external corrosion direct assessment in accordance with § 192.925, and internal corrosion direct assessment in accordance with § 192.927;

(B) Develop and implement procedures for conducting non-destructive tests, examinations, and assessments for cracks and crack-like defects, including but not limited to stress corrosion cracking, selective seam weld corrosion, girth weld cracks, and seam defects, for pipe at all excavations associated with anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, or any other reason for which the pipe segment is exposed, except for segments exposed during excavation activities that are in compliance with § 192.614;

(C) Conduct monthly patrols in Class 1 and 2 locations, at an interval not to exceed 45 days; weekly patrols in Class 3 locations not to exceed 10 days; and semi-weekly patrols in Class 4 locations, at an interval not to exceed six days, in accordance with § 192.705;

(D) Conduct monthly, instrumented leakage surveys in Class 1 and 2 locations, at intervals not to exceed 45 days; weekly leakage surveys in Class 3 locations at intervals not to exceed 10 days; and semi-weekly leakage surveys in Class 4 locations, at intervals not to exceed six days, in accordance with § 192.706; and

(E) Odorize gas transported in the segment, in accordance with § 192.625;

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

Under Method 5, future uprating of the segment in accordance with subpart K is allowed.

Method 6: In-Line Inspection in-lieu of Hydrostatic Pressure Testing – Conduct in-line inspection assessments utilizing one or more in-line inspection tools that have been qualified to detect defects that would fail pressure test equal to the verified MAOP divided by the greater of either 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or § 192.620(a)(2)(ii).
(7) Method 7: Alternative Technology - Operators may use an alternative technical evaluation process approach that provides a sound engineering basis for establishing verifying maximum allowable operating pressure. If an operator elects to use alternative technology, the operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph § 192.624(e) of this section. The operator must submit the alternative technical evaluation to PHMSA with the notification and obtain a “no objection letter” from the Associate Administrator of Pipeline Safety prior to usage of alternative technology—the operator must be prepared to provide technical justification that demonstrates the prudence of the approach used. The justification notification must include the following details:

(i) Descriptions of the technology or technologies to be used for tests, examinations, and assessments, establishment of material properties, and analytical techniques, with like-similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated.

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

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

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

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

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

(vii) Remediation methods with proven technical practice;

(viii) Schedules for assessments and remediation;

(ix) Operational monitoring procedures;

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

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

(d) Fracture Mechanics Modeling for failure stress and crack growth analysis:

(1) Applicability: Pipelines that contain or may be susceptible to cracks or crack-like on pipe with a longitudinal joint factor less than 1.0 as defined in §192.113, or was known to be installed using construction techniques no longer recognized as acceptable for new construction under part 192, and that operate at a hoop stress greater than 30% SMYS must be analyzed under the following circumstances:

(i) Operators conducting MAOP Verification as described in 192.624, using Method 3 (Engineering Critical Assessment) or Method 6 (Alternative Technology) must calculate remaining life of the segment considering the cyclic fatigue mechanism. Additionally, operators using Method 1 (Pressure Test) or Method 2 (Pressure Reduction), and who wish to use a less conservative pressure test or pressure reduction factor, must calculate remaining life of the segment considering the cyclic fatigue mechanism.
(ii) Operators responding to crack or crack-like indications from ILI inspections must calculate failure pressure of the anomaly, and must calculate remaining life if the anomaly cannot be directly examined within one year from the date of discovery.

(2) Fatigue analysis must be performed using a recognized form of the Paris Law or other technically appropriate engineering methodology validated by a subject matter expert in metallurgy and fracture mechanics to give conservative predictions of flaw growth and remaining life.

(i) If actual material toughness is not known or not adequately documented for fracture mechanics modeling for failure stress pressure, the operator must use a conservative Charpy energy value to determine the toughness based upon the material documentation program specified in § 192.607; or use maximum Charpy energy values of 15.0 ft-lb for body cracks; 5.0 ft-lb for cold weld, lack of fusion, and selective seam weld corrosion defects; or other appropriate values based on technology or technical publications that an operator demonstrates can provide a conservative Charpy energy values of the crack-related conditions of the line pipe.

(ii) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other). Examples of suitable models include: for the brittle failure mode, the Raju/Newman Model (Task 4.5); for the ductile failure mode, the Modified LnSec model (Task 4.5).

(iii) The operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired, but within 15 years. The operator must determine and document if further pressure tests or use of other methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.

(3) The analysis required by this paragraph must be reviewed and confirmed by a subject matter expert in both fracture mechanics.

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

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

2. Sending the notification to the Information Resources Manager by facsimile to (202) 366-7128; or

3. Sending the notification to the Information Resources Manager by e-mail to InformationResourcesManager@dot.gov.

4. An operator must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

(f) Records. For gas transmission pipelines that meet the applicability of §192.624, after [insert effective date of rule] Each operator must keep for the life of the pipeline reliable, traceable, verifiable, and complete records of the investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions made in accordance with the requirements of this section.

Subpart M – Maintenance
§192.710 Pipeline Assessments

(Moved to Subpart Q)

§192.711 Transmission lines: General requirements for repair procedures.

(a) Temporary repairs. Each operator must take immediate temporary measures to protect the public whenever:
   (1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and
   (2) It is not feasible to make a permanent repair at the time of discovery.

(b) Permanent repairs. An operator must make permanent repairs on its pipeline system according to the following:
   (1) Non-integrity management repairs: Whenever an operator discovers any condition on pipelines covered by §192.710 [Subpart Q] that could adversely affect the safe operation of a pipeline segment not covered under subpart O–Gas Transmission Pipeline Integrity Management, it must correct the condition as prescribed in §192.713 [§192.1113]. If an operator finds a condition that meets the criteria within §192.713(d)(1) [§192.1113 (d)(1)] on pipelines not covered by Subpart O or §192.710 [Subpart Q], operators will repair the condition immediately upon discovery. All other conditions will be repaired as soon as feasible. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator must reduce the operating pressure to a level not exceeding 80% of the operating pressure at the time the condition was discovered and take additional immediate temporary measures in accordance with paragraph (a) to protect persons or property. The operator must make permanent repairs as soon as feasible.
   (2) Integrity management repairs: When an operator discovers a condition on a pipeline covered under Subpart O-Gas Transmission Pipeline Integrity Management, the operator must remediate the condition as prescribed by §192.933(d).

[Repair Criteria for pipelines outside of HCAs is moved to Subpart Q - §192.1113]

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

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

(b) Operating pressure must be at a safe level during repair operations.

Subpart O – Gas Transmission Pipeline Integrity Management

§192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework (see §192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When
indicated, refer to ASME/ANSI B31.8S (incorporated by reference, see §192.7) for more detailed information on the listed element.)
(a) An identification of all high consequence areas, in accordance with §192.905.
(b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.
(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§192.917) and to evaluate the merits of additional preventive and mitigative measures (§192.935) for each covered segment.
(d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed, of §§192.925, 192.927, or 192.929.
(e) Provisions meeting the requirements of §192.933 for remediating conditions found during an integrity assessment.
(f) A process for continual evaluation and assessment meeting the requirements of §192.937.
(g) If applicable, a plan for confirmatory direct assessment meeting the requirements of §192.931.
(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area.
(i) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of §192.945.
(j) Record keeping provisions meeting the requirements of §192.947.
(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.
(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.
(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by—
   (1) OPS; and
   (2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.
(n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to—
   (1) OPS; and
   (2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.
(o) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.
(p) A process for identification and assessment of newly-identified high consequence areas. (See §192.905 and §192.921.)

§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?
(a) Threat identification. An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see §§192.7), section 2, which are grouped under the following four categories:
   (1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;
   (2) Static or resident threats, such as manufacturing, welding/fabrication or equipment construction defects;
(3) Time independent threats such as third party damage/mechanical damage, incorrect operational procedure, weather related and outside force damage; including consideration of seismicity, geology, and soil stability of the area; and
(4) Human error such as operational mishaps and design and construction mistakes.

(b) **Data gathering and integration.** To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather, verify, validate, and integrate existing data and information on the entire pipeline that could be relevant to the covered segment, and should consider verifying and validating data to the best extent practicable. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator should consider gathering and evaluating the set of data specified in paragraph (b)(1) of this section and Appendix A to ASME/ANSI B31.8S. The evaluation must analyze both the covered segment and similar non-covered segments, and must consider:

(1) Integration of information about pipeline attributes and other relevant information, including, but not limited to the applicable datasets detailed below. If an operator is missing data or if data deficiencies exist, inferred or conservative and reasonable assumptions shall be used when performing the subsequent risk assessment:
   (i) Pipe diameter, wall thickness, grade, seam type and joint factor;
   (ii) Manufacturer and manufacturing date, including manufacturing data and records;
   (iii) Material properties including, but not limited to, diameter, wall thickness, grade, seam type, yield strength, ultimate tensile strength, hardness, toughness, hard spots, and chemical composition;
   (iv) Equipment properties;
   (v) Year of installation;
   (vi) Bending method;
   (vii) Joining method, including process and inspection results;
   (viii) Depth of cover surveys including stream and river crossings, navigable waterways, and beach approaches;
   (ix) Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;
   (x) Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;
   (xi) Pipe coating methods (both manufactured and field applied) including method or process used to apply girth weld coating, inspection reports, and coating repairs;
   (xii) Soil, backfill;
   (xiii) Construction inspection reports, including but not limited to:
      (A) Girth weld non-destructive examinations;
      (B) Post backfill coating surveys;
      (C) Coating inspection (“jeeping”) reports;
   (xiv) Cathodic protection installed, including but not limited to type and location;
   (xv) Coating type;
   (xvi) Gas quality;
   (xvii) Flow rate;
   (xviii) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);
   (xix) Class location;
(xx) Leak and failure history including any in-service ruptures or leaks from incident reports, abnormal operations, safety related conditions (both reported and unreported) and failure investigations required by §§192.617, and their identified causes and consequences;

(xxi) Coating condition;

(xxii) CP system performance;

(xxiii) Pipe wall temperature;

(xxiv) Pipe operational and maintenance inspection reports, including but not limited to:

(A) Data gathered through integrity assessments required under this part, including but not limited to in-line inspections, pressure tests, direct assessment, guided wave ultrasonic testing, or other methods;

(B) Close interval survey (CIS) and electrical survey results;

(C) Cathodic protection (CP) rectifier readings;

(D) CP test point survey readings and locations;

(E) AC/DC and foreign structure interference surveys;

(F) Pipe coating surveys, including surveys to detect coating damage, disbonded coatings, or other conditions that compromise the effectiveness of corrosion protection, including but not limited to direct current voltage gradient or alternating current voltage gradient inspections;

(G) Results of examinations of exposed portions of buried pipelines (e.g., pipe and pipe coating condition, see §§192.459), including the results of any non-destructive examinations of the pipe, seam or girth weld, i.e. bell hole inspections;

(H) Stress corrosion cracking (SCC) excavations and findings;

(I) Selective seam weld corrosion (SSWC) excavations and findings;

(J) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;

(xxv) Outer Diameter/Inner Diameter corrosion monitoring;

(xxvi) Operating pressure history and pressure fluctuations, including analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;

(xxvii) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;

(xxviii) Encroachments and right-of-way activity, including but not limited to, one-call data, pipe exposures resulting from encroachments, and excavation activities due to development or planned development along the pipeline;

(xxix) Repairs;

(xxx) Vandalism;

(xxxi) External forces;

(xxxii) Audits and reviews;

(xxxiii) Industry experience for incident history;

(xxxiv) Aerial photography;

(xxxv) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area; and

(xxxvi) Other pertinent information derived from operations and maintenance activities and any additional tests, inspections, surveys, patrols, or monitoring required under this Part.

(2) Use objective, traceable, verified, and validated information and data as inputs, to the maximum extent practicable. If input is obtained from subject matter experts (SMEs), the operator must employ measures to adequately correct any bias in SME input. Bias control measures may include
training of SMEs and use of outside technical experts (independent expert reviews) to assess quality of processes and the judgment of SMEs. Operator must document the names of all SMEs involved in data verification, validation and information submitted by the SMEs for the life of the pipeline.

(3) Identify and analyze spatial relationships among anomalous information (e.g., corrosion coincident with foreign line crossings; evidence of pipeline damage where overhead imaging shows evidence of encroachment). Storing or recording the information in a common location, including a geographic information system (GIS), alone, is not sufficient; and

(4) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.

c) Risk assessment. An operator must conduct a risk assessment that analyzes the identified threats and potential consequences of an incident for each covered segment. The risk assessment must include evaluation of the effects of interacting threats, including the potential for interactions of threats and anomalous conditions not previously evaluated. An operator must should ensure validity of the methods used to conduct the risk assessment in light of incident, leak, and failure history and other historical information. Validation must should ensure the risk assessment methods produce a risk characterization that is consistent with the operator’s and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the factors used to characterize both the probability of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to determine additional preventive and mitigative measures needed (§192.935) for each covered segment, and periodically evaluate the integrity of each covered pipeline segment (§ §192.937(b)). The risk assessment must:

(1) Analyze how a potential failure could affect high consequence areas, including the consequences of the entire worst-case incident scenario from initial failure to incident termination;

(2) Analyze the likelihood of failure due to each individual threat or risk factor, and each unique combination of threats or risk factors that interact or simultaneously contribute to risk at a common location;

(3) Lead to better understanding of the nature of the threat, the failure mechanisms, the effectiveness of currently deployed risk mitigation activities, and how to prevent, mitigate, or reduce those risks;

(4) Account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and

(5) Evaluate the potential risk reduction associated with candidate risk reduction activities such as preventive and mitigative measures and reduced anomaly remediation and assessment intervals.

d) Plastic transmission pipeline. An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe.

e) Actions to address particular threats. If an operator identifies any of the following threats, the operator must take the following actions to address the threat such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.

(1) Third party damage. An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party
damage, the operator must implement comprehensive additional preventive measures in accordance with §§192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §§192.921, or a reassessment under §§192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.

An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(2) Cyclic fatigue. An operator must evaluate whether cyclic fatigue or other loading conditions (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment. Fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis must be conducted should be considered in accordance with §192.624(d) for cracks. Cyclic fatigue analysis must be annually, not to exceed 15 months.

(3) Manufacturing and construction defects. An operator must analyze the covered segment to determine the risk of failure from if an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment. An operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to a hydrostatic pressure testing satisfying the criteria of subpart J of at least 1.25 times MAOP, or has been subjected to a pressure reduction of 1.25 times the highest documented operating pressure, or has been assessed by an in-line inspection tool qualified to detect defects that would fail a pressure test of 1.25 times the highest documented operating pressure, and the segment has not experienced an reportable in-service incident attributed to a manufacturing or construction defect as identified through publicly available records from PHMSA the date of the pressure test. If the manufacturing or construction defects cannot be confirmed as stable, remediation of the threat will be completed in accordance with the schedule provided in §192.624(b). If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment, and must reconfirm or reestablish MAOP in accordance with §§192.624(c).

(i) The segment has experienced an reportable in-service incident as defined in 192.3 due to a manufacturing-related defect, a construction-related defect, or fabrication-related defect described in §§192.624(a)(1).

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) ERW pipe. If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe, pipe with seam factor less than 1.0 as defined in §§192.113, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including but not limited to pipe body cracking, seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure.
experienced during the preceding five years (including abnormal operation as defined in §§192.605(c)), or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment or a subsequent reassessment. Pipe with cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with §192.624 (c)and (d).

(5) **Corrosion.** If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §§192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part §192 for testing and repair.

§192.921 How is the baseline assessment to be conducted?

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

(1) Internal inspection tool or tools capable of detecting corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girl weld cracks), hard spots with cracking, any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. A person qualified by knowledge, training, and experience must analyze the data obtained from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;

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

(3) “Spike” hydrostatic pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for threats such as stress corrosion cracking, selective seam weld corrosion, manufacturing and related defects, including defective pipe and pipe seams, and other forms of defect or damage involving cracks or crack-like defects;
(4) Excavation and in situ direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI);

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

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (d)(5) of this section. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

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

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

(c) Assessment for particular threats. In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §192.917(e) to address particular threats that it has identified.

(d) Time period. An operator must prioritize all the covered segments for assessment in accordance with §192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

(e) Prior assessment. An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in §192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of §192.937 and §192.939.

(f) Newly identified areas. When an operator identifies a new high consequence area (see §192.905), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.

(g) Newly installed pipe. An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.

(h) Plastic transmission pipeline. If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of §192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.
§192.923 How is direct assessment used and for what threats?

(a) General. An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (EC), internal corrosion (IC), and stress corrosion cracking (SCC).

(b) Primary method. An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in—

1. Section 192.925 and ASME/ANSI B31.8S (incorporated by reference, see §192.7) section 6.4, and NACE SP0502 (incorporated by reference, see §192.7), if addressing external corrosion (EC).
2. Section 192.927, and ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.4, appendix B2 or NACE SP0206-2006 if addressing internal corrosion (ICDA).
3. Section 192.929, and ASME/ANSI B31.8S (incorporated by reference, see §192.7), appendix A3 or NACE SP0204-2008 if addressing stress corrosion cracking (SCCDA).

(c) Supplemental method. An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in §192.931.

§192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(a) Definition. Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO₂, O₂, hydrogen sulfide or other contaminants present in the gas.

(b) General requirements. An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206-2006 or ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.4 and appendix B2. The Dry Gas (DG) ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas (see definition §192.3), and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment in accordance with §192.921 (a)(4) or §192.937(c)(4).

(c) The ICDA plan. An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring and meets all requirements and recommendations contained in NACE SP0206-2006 and that implements all four steps of the DG-ICDA process including pre-assessment, indirect inspection, detailed examination, and post-assessment. The plan must identify where all ICDA Regions with covered segments are located in the transmission system. An ICDA Region is a continuous length of pipe (including weld joints) uninterrupted by any significant
change in water or flow characteristics that includes similar physical characteristics or operating history. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located in order to complete the assessment of the covered segment.

(1) **Preassessment.** An operator must comply with the requirements and recommendations in NACE SP0206-2006 in conducting the preassessment step of the ICDA process. Gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to—

(i) All data elements listed in appendix A2 of ASME/ANSI B31.8S;

(ii) Information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (See paragraph (a) of this section.) This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline;

(iii) Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and

(iv) Information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.

(2) **ICDA region identification.** An operator’s plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02-0057, “Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology,” (incorporated by reference, see §192.7). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02-0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations down stream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas. An operator must comply with the requirements and recommendations in NACE SP0206-2006, and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. Operators must explicitly document the results of its feasibility assessment as required by NACE SP0206-2006, Section 3.3; if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use pipeline specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of data used to make those calculations, including but not limited to gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile...
at features with inclinations such as road crossing, river crossings, drains, valves, drips, etc.), topographical data, depth of cover, etc. The operator must select locations for direct examination, and establish the extent of pipe exposure needed (i.e., the size of the bell hole), to explicitly account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

(3) Identification of locations for excavation and direct examination. An operator’s plan must identify the locations where internal corrosion is most likely in each ICDA region. An operator must comply with the requirements and recommendations in NACE SP0206-2006 in conducting the detailed examination step of the ICDA process. In addition, on the first use of ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each ICDA Region and must perform a detailed examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must—

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with §192.933; if the condition is in a covered segment, or in accordance with §§ 192.485 and 192.713 if the condition is not in a covered segment;

(ii) Expand the detailed examination program, whenever internal corrosion is discovered, to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined per paragraph (3) of this section, two additional detailed examinations must be conducted within the covered segment; and

(iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator’s pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with §192.933 or § 192.713, as appropriate.

(4) Post-assessment evaluation and monitoring. An operator’s plan must comply with the requirements and recommendations in NACE SP0206-2006 in performing the post-assessment step of the ICDA process. provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. In addition the post-assessment requirements and recommendations in NACE SP0206-2006, the evaluation and monitoring process includes—

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals
than those specified in §192.939. An operator must carry out this evaluation within a year of conducting an ICDA;

(ii) Validation of the flow modeling calculations by comparison of actual locations of discovered internal corrosion with locations predicted by the model (if the flow model cannot be validated, the ICDA is not feasible for the segment); and

(iii) Continually monitoring each ICDA region which contains a covered segment where internal corrosion has been identified using techniques such as coupons or UT sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the ICDA region. At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7½ months. If an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with § 192.933.

(A) Conduct excavations of, and detailed examinations at, locations downstream from where the electrolyte might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of § 192.478; or

(B) Assess the covered segment using ILI tools capable of detecting internal corrosion or another integrity assessment method allowed by this subpart.

§192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

(a) Definition. Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

(b) General requirements. An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must develop and follow an SCCDA plan that, at minimum, — meets all requirements and recommendations contained in NACE SP0204-2008 and that implements all four steps of the SCCDA process including pre-assessment, indirect inspection, detailed examination and post-assessment. As specified in NACE SP0204-2008, Section 1.1.7, SCCDA is complementary with other inspection methods such as in-line inspection (ILI) or hydrostatic testing and is not necessarily an alternative or replacement for these methods in all instances. In addition, the plan must provide for—

(1) Data gathering and integration. An operator’s plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment in accordance with NACE SP0204-2008, Sections 3 and 4, and Table 1. This process must also include gathering and evaluating data related
to SCC at all sites an operator excavates during the conduct of its pipeline operations (both within and outside covered segments) where the criteria in ASME/ANSI B31.8S (incorporated by reference, see §192.7), appendix A3.3 or NACE SP0204-2008, Section 5.3 indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204-2008, Section 5.3, and must include, at minimum, the data specified in ASME/ANSI B31.8S, appendix A3 or data listed in NACE SP0204-2008, Table 2. Further the following factors must be analyzed as part of this evaluation:

(i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment such as soil temperature, moisture, the presence or generation of carbon dioxide, and/or Cathodic Protection (CP).

(ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments.

(iii) The effects of variations in applied CP such as overprotection, CP loss for extended periods, and high negative potentials.

(iv) The effects of coatings that shield CP when disbonded from the pipe.

(v) Other factors which affect the mechanistic properties associated with SCC including but not limited to historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.

(2) Assessment method. The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4 or—in addition to the requirements and recommendations of NACE SP0204-2008, section 4. The plan’s procedures for indirect inspection must include provisions for conducting at least two above ground surveys using complementary measurement tools most appropriate for the pipeline segment based on the data gathering and integration step.

(3) Direct examination. In addition to the requirements and recommendations of NACE SP0204-2008, The plan’s procedures for direct examination must provide for conducting a minimum of three direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur.

(4) Remediation and mitigation. If any indication of SCC is discovered in a segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Removing the pipe with SCC, remediating the pipe with a Type B sleeve, hydrostatic testing in accordance with (b)(4)(ii), below, or by grinding out the SCC defect and repairing the pipe. If grinding is used for repair, the repair procedure must include: nondestructive testing for any remaining cracks or other defects; measuring remaining wall thickness; and the remaining strength of the pipe at the repair location must be determined using ASME/ANSI B31G or RSTRENG and must be sufficient to meet the design requirements of subpart C of this part. Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgements may be used.
(ii) Significant SCC must be mitigated using a spike pressure test in accordance with §192.506. The maximum allowable operating pressure will be equal to the test pressure specified in §192.506(c) divided by the greater of 1.25 or the applicable class location factor in §192.619(a)(2)(ii) or 192.620(a)(2)(ii). Hydrostatic testing program to a minimum test pressure equal to 105 percent of the specified minimum yield strength of the pipe for 30 minutes immediately followed by a pressure test in accordance with §192.506, but not lower than 1.25 times MAOP. The test pressure for the entire sequence must be continuously maintained for at least 8 hours, in accordance with §192.506 and must be above the minimum test factors in §§192.619(a)(2)(ii) or 192.620(a)(2)(ii), but not lower than 1.25 times maximum allowable operating pressure. Any test failures due to SCC must be repaired by replacement of the pipe segment, and the segment re-tested until the pipe passes the complete test without leakage. Pipe segments that have SCC present, but that pass the pressure test, may be repaired by grinding in accordance with paragraph (b)(4)(i).

(5) Post assessment. In addition to the requirements and recommendations of NACE SP0204-2008, sections 6.3, periodic reassessment, and 6.4, effectiveness of SCCDA, The operator’s procedures for post assessment must include development of a reassessment plan based on the susceptibility of the operator’s pipe to SCC as well as on the mechanistic behavior of identified cracking. Reassessment intervals must comply with section 192.939 of this part. Factors that must be considered include, but are not limited to:

(i) Evaluation of discovered crack clusters during the direct examination step in accordance with NACE RP0204-2008, sections 5.3.5.7, 5.4, and 5.5;

(ii) Conditions conducive to creation of the carbonate-bicarbonate environment;

(iii) Conditions in the application (or loss) of CP that can create or exacerbate SCC;

(iv) Operating temperature and pressure conditions including operating stress levels on the pipe;

(v) Cyclic loading conditions;

(vi) Mechanistic conditions that influence crack initiation and growth rates;

(vii) The effects of interacting crack clusters;

(viii) The presence of sulfides; and.

(ix) Disbonded coatings that shield CP from the pipe.

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

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

(1) Temporary pressure reduction. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, see §192.7); AGA Pipeline Research Council, International, PR-3-805 (R-STRENG) (incorporated by reference, see §192.7) to determine the safe operating pressure.
that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. Pipe and material properties used in the remaining strength calculation must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based in accordance with §192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgements may be used. An operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement or an intrastate covered segment is regulated by that State.

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

(b) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period the operator must notify OPS, in accordance with §192.949, and provide an expected date when adequate information will become available.

(c) Schedule for evaluation and remediation. An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) Special requirements for scheduling remediation —

(1) Immediate repair conditions. An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions if confirmed:

(i) Calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly for any class location. Suitable remaining strength calculation methods include ASME/ANSI B31G (incorporated by reference, see §192.7), PRCI PR-3-805 (R-STRENG)
(incorporated by reference, see §192.7), or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result. Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with §192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound judgements may be used.

(ii) A dent that has any indication of metal loss such as a scratch, a gouge, or stress riser.

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

(iv) Metal loss greater than 80% of nominal wall regardless of dimensions.

(v) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency, or high risk high frequency electric resistance welding or by electric flash welding.

(vi) Any indication of significant stress corrosion cracking (SCC).

(vii) Any indication of significant selective seam weld corrosion (SSWC). An indication of metal loss greater than or equal to 20% of nominal wall selectively affecting a detected longitudinal seam other than those seam types listed in §192.933(d)(1)(v).

(2) One-year conditions. Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of the confirmed discovery of the condition:

(i) A smooth dent located between the 8 o’clock and 4 o’clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) 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 longitudinal seam weld.

(iii) A calculation of the remaining strength of the pipe shows a predicted failure pressure ratio at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations.

(iv) An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.

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

(vi) A gouge or groove greater than 12.5% of nominal wall.

(vii) Any indication of crack or crack-like defect other than an immediate condition.

(viii) An indication of metal loss less than 20% of nominal wall selectively affecting a detected longitudinal seam other than those seam types listed in §192.933(d)(1)(v).

(ix) A dent that has any indication of metal loss due to corrosion.

(3) Monitored conditions. An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) 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).
(ii) A dent located between the 8 o’clock and 4 o’clock positions (upper \( \frac{2}{3} \) 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.

(iii) A dent with a depth greater than 2% of the pipeline’s diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

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

(a) General requirements. An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Such additional measures must be based on the risk analysis required by §192.917, and must include actions such as but are not limited to: correction of the root cause of past incidents to prevent reoccurrence; establishing and implementing adequate operations and maintenance processes that could increase safety; establishing and deploying adequate resources for successful execution of preventative and mitigative measures; installing Automatic Shut-off Valves or Remote Control Valves; installing pressure transmitters on both sides of automatic shut-off valves and remote control valves that communicate with the pipeline control center; installing computerized monitoring and leak detection systems; replacing pipe segments with pipe of heavier wall thickness or higher strength; conducting additional right-of-way patrols; conducting hydrostatic tests in areas where material has quality issues or lost records; tests to determine material mechanical and chemical properties for unknown properties that are needed to assure integrity or substantive MAOP evaluations including material property tests from removed pipe that is representative of the in-service pipeline; re-coating of damaged, poorly performing or disbonded coatings; applying additional depth-of-cover survey at roads, streams and rivers; remediating inadequate depth-of-cover; providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

(b) Third party damage and outside force damage—

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

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

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

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

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

(c) Automatic shut-off valves (ASV) or Remote control valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

(d) Pipelines operating below 30% SMYS. An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.

(1) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and

(2) Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.

(3) Perform semi-annual, instrumented leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where indirect assessments, i.e. indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient or equivalent are impractical) and an assessment per §192.921 has not been performed.

(e) Plastic transmission pipeline. An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and (b)(1)(iv) of this section to the covered segments of the pipeline.

(f) Internal corrosion. As an operator finds evidence of gains information about internal corrosion on a pipeline, it must enhance its internal corrosion management program, as required under Subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to internal corrosion. At a minimum, as part of this enhancement, operators must consider—

(1) Monitoring for, and mitigating the presence of, deleterious gas stream constituents.

(3) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators and continuous gas quality monitoring equipment at least once per quarter. Use gas quality monitoring equipment that includes, but is not limited to, a moisture
analyzer, chromatograph, carbon dioxide sampling, and hydrogen sulfide sampling. (See 192.478 for monitoring frequency)

(2) At least once per quarter, use gas quality monitoring equipment that includes, but is not limited to, a moisture analyzer, chromatograph, carbon dioxide sampling, and hydrogen sulfide sampling.

(3) Use cleaning pigs and sample accumulated liquids and solids, including tests for microbiologically induced corrosion.

(4) Use inhibitors or other mitigative measures when corrosive gas or corrosive liquids are known to be present.

(5) Address potentially corrosive gas stream constituents as specified in § 192.478(a), where the volumes exceed these amounts over a 24-hour interval in the pipeline as follows:
   (i) Limit carbon dioxide to three percent by volume;
   (ii) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and
   (iii) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas. If the hydrogen sulfide concentration is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points.

(6) Review the program at least semi-annually based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.

(g) External corrosion. As an operator finds evidence of gains information about external corrosion on a pipeline, it must enhance its external corrosion management program, as required under Subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to external corrosion. At a minimum, as part of this enhancement, operators must develop a plan to monitor and -

(1) Control electrical interference currents that can adversely affect cathodic protection as follows:
   (i) As frequently as needed (such as when new or uprated high voltage alternating current power lines greater than or equal to 69 kVA or electrical substations are co-located near the pipeline), but not to exceed every seven years., perform the following:
      (A) Conduct an interference survey (at times when voltages are at the highest values for a time period of at least 24 hours) to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected;
      (B) Analyze the results of the survey to identify locations where interference currents are greater than or equal to 20 Amps per meter squared; and
      (C) Take Initiate any remedial action needed within six eighteen months after completing the survey to protect the pipeline segment from deleterious current. Remedial action means the implementation of measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. Any location with interference currents greater than 50 Amps per meter squared must be remediated. If any AC interference between 20 and 50 Amps per meter squared is not remediated, the operator must provide and document an engineering justification.

(2) Confirm the adequacy of external corrosion control through indirect assessment as follows:
   (i) Periodically (as frequently as needed but at intervals not to exceed seven years) assess the adequacy of the cathodic protection through an indirect assessment method such as close-interval survey, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG).
(ii) RemEDIATE any damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dBμv for ACVG) under section 4 of NACE RP0502–2008 (incorporated by reference, see § 192.7).

(iii) Integrate the results of the indirect assessment required under paragraph (g)(2)(i) of this section with the results of the most recent integrity assessment required by this subpart and promptly take any needed remedial actions no later than 6 months after assessment finding.

(iv) Perform periodic assessments as follows:
   (D) Conduct periodic close interval surveys with current interrupted to confirm voltage drops in association with integrity assessments under sections §§ 192.921 and 192.937 of this subpart.
   (E) Locate pipe-to-soil test stations at half-mile intervals within each covered segment, ensuring at least one station is within each high consequence area, if practicable.
   (F) Integrate the results with those of the baseline and periodic assessments for integrity done under sections §§ 192.921 and 192.937 of this subpart.

(3) Control external corrosion through cathodic protection as follows:
   (i) If an annual test station reading indicates cathodic protection below the level of protection required in subpart I of this part, complete assessment and remedial action, as required in § 192.465(f), within 6 months of the failed reading or notify each PHMSA pipeline safety regional office where the pipeline is in service and demonstrate that the integrity of the pipeline is not compromised if the repair takes longer than 6 months. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and
   (ii) RemEDIATE insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline in accordance with paragraph (i) above, including use of indirect assessments or direct examination of the coating in areas of low CP readings unless the reason for the failed reading is determined to be a short to an adjacent foreign structure, rectifier connection or power input problem that can be remediated and restoration of adequate cathodic protection can be verified. The operator must confirm restoration of adequate corrosion control by a close interval survey on both sides of the affected test stations to the adjacent test stations.

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

(a) General. After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917, which incorporates an analysis of updated pipe design, construction, operation, maintenance, and integrity information. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other
transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933). The evaluation must identify the threats specific to each covered segment, including interacting threats and the risk represented by these threats, and identify additional preventive and mitigative actions (§192.935).

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

1) Internal inspection tool or tools capable of detecting corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots, and any other threats to which the covered segment is susceptible. When performing an assessment using and in-line inspection tool, an operator must comply with § 192.493. A person qualified by knowledge, training, and experience must analyze the data obtained from an assessment performed under paragraph (b) of this section to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing anomalies.

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

3) “Spike” hydrostatic pressure test in accordance with §192.506. The use of spike hydrostatic pressure testing is appropriate for threats such as stress corrosion cracking, selective seam weld corrosion, manufacturing and related defects, including defective pipe and pipe seams, and other forms of defect or damage involving cracks or crack-like defects.

4) Excavation and in situ direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI). An operator must explicitly consider uncertainties in in situ direct examination results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, and usage unity chart plots or equivalent for determining uncertainties and verifying performance on the type defects being evaluated) in identifying and characterizing anomalies.

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

6) Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (c)(1)
An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

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

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

Subpart Q – Reliability Assessments Outside of HCAs

§192.1101 What do the regulations in this subpart cover?

(a) This subpart prescribes the assessment requirements for steel transmission lines located in Class 3 and 4 locations or steel pipeline segments that are located in moderate consequence areas (MCAs) that can accommodate inspection by means of instrumented inline inspection tools (i.e., “smart pigs”) as defined in §192.3.

(b) This subpart does not apply to pipeline segments located in a High Consequence Areas as defined in §192.903.

§192.1103 What definitions apply to this subpart?

Assessment Segment means a pipeline segment located in one of the following locations that is not meeting all the requirements of Subpart O of this part:

(a) A non-HCA Class 3 location under §192.5; or
(b) A non-HCA Class 4 location under §192.5; or
(c) A moderate consequence area as defined in § 192.3, if the pipeline can accommodate inspection by means of instrumented inline inspection tools (i.e., “smart pigs”); or
(d) A non-HCA pipeline, not located in one of the previous locations, that the operator chooses to include in Subpart Q based on the risk analysis of their system.

Moderate consequence area – This term is defined in §192.3.

§192.1105 How does an operator identify an Assessment Segment?

To determine which segments of an operator’s transmission pipeline system are covered by this subpart, an operator must identify class 3 and 4 locations and moderate consequence areas. An operator must follow the definitions of a moderate consequence area in §192.3 when identifying moderate consequence areas.

§192.1107 What must an operator do to implement this subpart?
(a) No later than [insert date 1 year after the effective date of the final rule], an operator of a pipeline segment subject to this subpart must develop and follow a written assessment plan. The assessment plan must consist, at a minimum, of a framework that describes the process of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and for performing each assessment. An operator must review the plan periodically and make improvements as appropriate.

(b) Initial assessment - No later than [insert date that is 15 years after the effective date of the final rule] an operator must perform initial assessments.

(c) Subsequent assessments - No later than 20 years after an initial or subsequent assessment of a segment, an operator must perform a subsequent assessment. A shorter reassessment interval may be required based upon the type of anomaly, material, operational conditions and environmental conditions affecting the pipeline segment, or as otherwise necessary to ensure public safety.

(d) Prior assessment. An operator may use a prior assessment conducted before [Insert effective date of the final rule] as an initial assessment for the segment, if the assessment meets any the requirements of 192.1113. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (c) of this section.

(e) MAOP Verification. An operator may use assessment methods conducted in accordance with the requirements of §192.624(c) for verification of MAOP to meet the requirements of this subpart.

§ 192.1109 What assessment methods can an operator use?

The initial and the subsequent assessments required by § 192.1107 must be performed using one or more of the following methods:

(a) Internal inspection tool or tools capable of detecting the appropriate threats in accordance with § 192.493;

(b) Pressure test conducted in accordance with subpart J of this part. The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, manufacturing and related defect threats, including defective pipe and pipe seams, dents and other forms of mechanical damage;

(c) “Spike” hydrostatic pressure test in accordance with § 192.506;

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

(e) Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F;

(f) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in § 192.925, 192.927 or 192.929; or

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

§192.1111 What can an operator do for a low stress pipeline assessment?

For pipeline segments with MAOP less than 30% of the SMYS, in lieu of the requirements within §192.1109, an operator may assess for the threats of external and internal corrosion, as follows:
(a) **External corrosion.** An operator must take one of the following actions to address external corrosion on a low stress segment:

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

2. **Unprotected pipe or cathodically protected pipe where indirect assessments are impractical.** To address the threat of external corrosion on unprotected pipe or cathodically protected pipe where indirect assessments are impractical, an operator must—
   (i) Conduct leakage surveys as required by § 192.706 at 4-month intervals; and
   (ii) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(b) **Internal corrosion.** If an operator determines that internal corrosion is a threat on a low stress segment, an operator must—

1. Conduct a gas analysis for corrosive agents at least twice each calendar year;
2. Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a segment; and
3. At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (ii)(A)-(ii)(B) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

§ 192.1113 What actions must be taken to address imperfections and damages?

(a) **General.** Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made so as to prevent damage to persons, property, or the environment. Operating pressure must be at a safe level during repair operations.

1. **Temporary pressure reduction.** If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, see §192.7); AGA Pipeline Research Council, International, PR-3-805 (R-STRENG) (incorporated by reference, see §192.7) to determine the safe operating pressure that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. Pipe and material properties used in the remaining strength calculation must be documented in traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based in accordance with §192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgements may be used. An
operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement or an intrastate covered segment is regulated by that State.

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

(b) **Repair.** Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

1. Removed by cutting out and replacing a cylindrical piece of pipe; or
2. Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(c) **Schedule for evaluation and remediation.** An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (e) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) **Remediation schedule.** For pipelines not located in high consequence areas, an operator must complete the remediation of a condition discovered after [the effective date of the rule] according to the following schedule:

1. **High priority conditions.** An operator must confirm and repair the following conditions immediately upon discovery:
   
   i. A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in § 192.7(c). Pipe and material properties used in remaining strength calculations must be documented in traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with §192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgments may be used.

   ii. A dent that has any indication of metal loss due to a scratch, a gouge, cracking or a stress riser.

   iii. Metal loss greater than 80% of nominal wall regardless of dimensions.

   iv. An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency or high risk high frequency electric resistance welding or by electric flash welding.
(v) Any indication of significant stress corrosion cracking (SCC).
(vi) An indication of metal loss greater than or equal to 20% of nominal wall selectively affecting a detected longitudinal seam other than those seam types listed in §192.1113(e)(1)(iv).
(vii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(2) Until the remediation of a condition specified in paragraph (d)(1) is complete, an operator must reduce the operating pressure of the affected pipeline to the lower of:

(i) A level that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, determined using ASME/ANSI B31G (“Manual for Determining the Remaining Strength of Corroded Pipelines” (1991) or AGA Pipeline Research Committee Project PR-3-805 (“A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe” (December 1989)) (“RSTRENG,” incorporated by reference, see § 192.7) for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, and crack-related defects, appropriate failure criteria and justification of the criteria must be used. If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by traceable, verifiable, and complete records, then the operator must determine the material properties based upon the material documentation program specified in §192.607. Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgments may be used; or
(ii) 80% of pressure at the time of discovery.

(3) Two-year conditions. An operator must confirm and repair the following conditions within two years of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).
(ii) 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 longitudinal or helical (spiral) seam weld.
(iii) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.
(iv) A gouge or groove greater than 12.5% of nominal wall.
(v) Any indication of a crack or crack-like defect other than an immediate condition.
(vi) An indication of metal loss less than 20% of nominal wall selectively affecting a detected longitudinal seam other than those seam types listed in §192.1113(e)(1)(iv).
(vii) A dent that has any indication of metal loss due to corrosion.

(4) Monitored conditions. An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and reliability assessments for any change that may require remediation:

(i) 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).
(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% 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.

e) In situ direct examination of crack defects. Operators must perform direct examination of known locations of cracks or crack-like defects using inverse wave field extrapolation (IWEX), phased array, automated ultrasonic testing (AUT), or equivalent technology that has been validated to detect tight cracks (equal to or less than 0.008 inches). In-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts in direct examination inspection for accuracy for the type of defects and pipe material being evaluated.

§ 192.1115 What does an operator do when a new pipeline segment is subject to this subpart?

A newly identified assessment segment must be incorporated into the assessment plan within one year of identification. An initial assessment of the newly identified segment is required within 15 years of being identified.

§ 192.1117 When can an operator deviate from assessment or reassessment intervals?

(a) Waiver from assessment or reassessment interval in limited situations. In the following limited instances, OPS may allow a waiver from an assessment or reassessment interval if OPS finds a waiver be consistent with pipeline safety.

(1) Lack of internal inspection tools. An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the pipeline segment.

(2) Inability to perform scheduled assessments or reassessments required by this subpart due to significant unplanned changes in Subpart O assessment schedule. To justify this, the operator must demonstrate that the additional Subpart O work contains the following:

   (i) Has a significantly higher priority than and takes precedence over the Subpart Q;

   (ii) All scheduled work cannot be done within the timeframe specified, and

   (iii) This work cannot have been anticipated with sufficient advance notice by the operator.

(3) Maintain product supply. An operator may be able to justify a longer assessment or reassessment period for a pipeline segment if the operator demonstrates that it cannot maintain local product supply if it conducts the assessment or reassessment within the required interval.

(b) How to apply. If one of the conditions specified in paragraph (a)(1), (a)(2), or (a)(3) of this section applies, an operator may seek a waiver of the required assessment or reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required assessment or reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.

§ 192.1119 How is the threat of manufacturing and construction defects addressed on the pipeline?
Manufacturing and construction defects. An operator must analyze the assessment segment to determine the risk of failure from manufacturing and construction defects (including seam defects) in the assessment segment. The analysis must consider the results of prior assessments on the assessment segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to a pressure test satisfying the criteria of subpart J of at least 1.25 times MAOP, or has been subjected to a pressure reduction of 1.25 times the highest documented operating pressure, or has been assessed by an in-line inspection tool qualified to detect defects that would fail a 1.25 times MAOP pressure test, and the segment has not experienced a reportable in-service incident attributed to a manufacturing or construction defect as identified through publicly available records from PHMSA. If any of the following changes occur in the assessment segment, an operator must prioritize the assessment segment as a high risk segment for the baseline assessment or a subsequent reassessment, and must reconfirm or reestablish MAOP in accordance with §192.624(c).

(a) The segment has experienced a reportable in-service incident as defined in §191.3 due to a manufacturing-related defect, a construction-, installation-, or fabrication-related defect as identified through publicly available records from PHMSA.
(b) MAOP increases; or
(c) The stresses leading to cyclic fatigue increase.

§ 192.1121 What records must an operator keep?

An operator must maintain records demonstrating compliance with the requirements of this subpart for the life of the pipeline.

Appendix D to Part 192 – Criteria for Cathodic Protection and Determination Measurements

I. Criteria for cathodic protection—
   E. Steel, cast iron, and ductile iron structures.
      (6) A negative (cathodic) voltage across the structure electrolyte boundary of at least 0.85 volt, with reference to a saturated copper-copper sulfate reference electrode, often referred to as a half cell. Determination of this voltage must be made in accordance with sections II and IV of this appendix.
      (7) A minimum negative (cathodic) polarization voltage shift of at least 300 400 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.
      (8) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.
      (9) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.
      (10) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.
   F. Aluminum structures.
      (5) Except as provided in paragraphs (2) and (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 150 200 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.
Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

Notwithstanding the alternative minimum criteria in paragraphs (1) and (2) of this paragraph, if aluminum is cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate reference electrode, in accordance with section IVII of this appendix, the aluminum may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

Copper structures. A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

Metals of different anodic potentials. A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (2) and (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

Interpretation of voltage measurement. Structure-to-electrolyte potential measurements must be made utilizing measurement techniques that will minimize voltage (IR) drops other than those across the structure-electrolyte boundary. All voltage (IR) drops other than those across the structure electrolyte boundary will be differentiated, such that the resulting measurement accurately reflects the structure-to-electrolyte potential.

Determination of polarization voltage shift. The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs often referred to as an instant off potential. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(2), B(1), and C of section I of this appendix.

Reference electrodes (half cells).

A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate reference electrode contacting the electrolyte.

B. Other standard reference electrodes may be substituted for the saturated copper-copper sulfate electrode. Two commonly used reference half cells electrodes are listed below along with their voltage equivalent to $-0.85$ volt as referred to a saturated copper-copper sulfate reference electrode:

1. Saturated KCl calomel half cell: $-0.78$ volt.
2. Silver-silver chloride reference electrode used in sea water: $-0.80$ volt.

C. In addition to the standard reference electrodes, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate reference electrode if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate reference electrode is established.
Appendix B

AGA’s Commitment to Enhancing Safety: Revised February 2016

AGA and its members are dedicated to the continued enhancement of pipeline safety. As such, we are committed to proactively collaborating with federal and state regulators, public officials, emergency responders, excavators, consumers, safety advocates and the public to continue improving the industry’s longstanding record of providing natural gas service safely, reliably and efficiently to 177 million Americans. AGA and its members support the development of reasonable regulations to meet federal objectives and National Transportation Safety Board recommendations.

Below are voluntary actions that are being taken by AGA or individual operators to help ensure safe and reliable operation of the nation’s 2.5 million miles of natural gas pipeline which span all 50 states with diverse geographic and operating conditions. AGA and its individual operators recognize the significant role that their state regulators or governing bodies play in supporting and funding these actions.

It is the consensus of AGA members that the actions listed below enhance safety, gas utility operations, and reduce greenhouse gas emissions when implemented as an integral part of each operator’s specific safety programs. However, both the need to implement and the timing of implementation of these actions will vary with each operator. Each operator will need to evaluate the actions in light of system and geographic variables, the operator’s independent integrity assessment, risk analysis and mitigation strategy and what has been deemed reasonable and prudent by their state regulators. Therefore, not all of these recommendations will be applicable to all operators.

Building Pipelines for Safety

Construction
- Expand requirements of the Operator Qualification rule to include new pipeline construction.
- Review established pipeline construction oversight procedures to ensure adequacy and compliance with those procedures.
- Implement industry leading practices when installing new pipelines to help prevent damage to other facilities.

Emergency Shutoff Valves
- Support a risk-based approach to the installation of automatic and/or remote control isolation valves where technically and operationally feasible on newly constructed or entirely replaced transmission lines.
- Work with regulatory agencies and policy makers to develop guidelines for consideration of automatic and/or remote control isolation valves on transmission lines that are in service.
- Expand the use of excess flow valves (E2Vs) to new and fully replaced branch services, small multi-family facilities, and small commercial facilities where technically and operationally feasible.

Operating Pipelines Safely

Integrity Management
- Advance integrity management programs and principles to mitigate system specific risks. This includes operational activities, repair, replacement or rehabilitation of pipelines and associated facilities where it will improve safety and reliability.
- Collaborate with stakeholders to develop and promote effective cost-recovery mechanisms to support pipeline assessment, repair, rehabilitation, and replacement programs.
- Develop industry guidelines for data management to advance data quality and knowledge related to pipeline integrity.
- Support development of processes and guidelines that enable the tracking and traceability of new pipeline components.

Excavation Damage Prevention
- Support strong enforcement of the 811—Call Before You Dig program, and advocate for the reduction of excavator exemptions within state damage prevention laws.
- Improve engagement between the operator and excavators on the need to call before digging to reduce excavation damage.

Physical and Cybersecurity/System Controls
- Take actions that help strengthen the physical and cybersecurity of the gas utility industry.
- Enhance system monitoring and control of gas systems.

Enhancing Pipeline Safety

Safety Knowledge Sharing
- Expand the voluntary national Peer Review Program to allow companies to observe their peers, identify what is working well, identify opportunities to improve, and share leading practices.
- Evaluate the work of other industries to improve safety. Identify and implement models that will assist in enhancing safety and encourage knowledge exchange among operators, contractors, government and the public.

Workforce Development
- Collaborate with industry, government, educational institutions and labor groups to develop solutions to address the need for a qualified, diverse workforce.

Public Awareness and Emergency Response
- Evaluate methods to effectively communicate with public officials, excavators, consumers, safety advocates and the public about the presence of pipelines. Implement tested and proven communication methods to enhance those communications.
- Partner with emergency responders to share information and improve emergency response coordination.

Pipeline Planning Engagement
- Work with a coalition of Pipelines and Informed Planning Alliance (PIPA) Guidance stakeholders to increase awareness of risk based land use options and adopt existing PIPA recommended best practices.

Advancing Technology Development
- Increase investment, continue participation, and support research, development and deployment of technologies to improve safety.
AGA's Commitment to Enhancing Safety: Industry Actions That Exceed 49 CFR Part 192

Building Pipelines for Safety

Construction
- Maintain a clearings process on effective cost-recovery mechanisms that states have used to fund infrastructure repair, replacement and rehabilitation projects.

Emergency Shutoff Valves
- Install EFVs on new and fully replaced branch services, small multi-family facilities, and small commercial facilities where technically and operationally feasible.

Operating Pipelines Safety

Integrity Management
- Advocate programs to accelerate the risk-based repair, rehabilitation and replacement of pipelines.
- Support development of processes and guidelines that enable tracking and traceability of pipeline components.
- Continue the Plastic Pipe Database Committee's work to collect and analyze plastic material failures.
- Incorporate systems and/or processes to reduce human error.
- Promote the use of API RP 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, and API RP 1170, Design and Operation of Solution-mined Salt caverns Used for Natural Gas Storage. This includes teleconferences, workshops and roundtables to share lessons learned from companies voluntarily adopting the recommended practices.

Excavation Damage Prevention
- Use a risk-based approach to improve excavation monitoring.
- Support the Common Ground Alliance, the use of 811 and other damage prevention initiatives through outreach, education, intervention and enforcement.
- Influence and/or support state legislation to strengthen damage prevention programs.
- Encourage participation in One-Call by all underground operators and excavators.

Physical and Cybersecurity/System Controls
- Participate in a Downstream Natural Gas Information Sharing & Analysis Center (DNG ISAC).
- Conduct cybersecurity vulnerability assessments.
- Collaborate with government to develop and implement guidance, such as DOE ONS-C2M2, DOE Energy Sector & TSA Transportation Sector Framework Implementation Guidance and NIST Energy Sector Cybersecurity Framework Implementation Guidance.
- Create industry guidance and hold events to strengthen the physical and cybersecurity of the natural gas infrastructure, including the Natural Gas Utility Threat Analysis Elements & Mitigations Guidance, Cybersecurity Procurement Language Guidance, an AGA Energy Delivery Cybersecurity Executive Summit, cyber threat analysis workshops, insider threat workshops, workshops on the Oil and Natural Gas Cybersecurity Capability Maturity Model (ONC2M2), and an annual AGA/EEI Security Conference.

Enhancing Pipeline Safety

Pipeline Safety Management Systems
- Promote the use of API RP 1173, Pipeline Safety Management System (PSMS) Recommended Practice, including piloting of the PSMS, teleconferences and workshops to share lessons learned, and tools that can help the industry implement the PSMS.
- Promote the AGA Safety Culture Statement and a positive safety culture throughout the natural gas industry.

Safety Knowledge Sharing
- Convene AGA Board Safety Committee initiatives, such as sharing lessons learned through the Safety Information Resource Center, safety alerts through AGA’s Safety Alert System, safety communications with customers, supporting AGA’s Safety Culture Statement, and holding an annual Executive Leadership Safety Summit.
- Recognize statistical top safety performers, promote safety performance and encourage knowledge sharing through AGA Safety Awards.
- Convene the work of the AGA Best Practices Programs to identify superior performing companies and innovative work practices that can be shared with others to improve operations and safety.
- Convene workshops, teleconferences, discussion groups, and other events to share information including pipeline safety reauthorization, DIMP/TIMP, fitness for service, records, in-line inspection, emergency response, and other key safety initiatives.

Workforce Development
- Support of the efforts of the Center for Energy Workforce Development, Energetic Women, natural gas boot camps, regional gas associations, and educational institutes on solutions to address the need for a qualified, diverse workforce.

Public Awareness and Emergency Response
- Explore ways to educate, engage and provide appropriate information to stakeholders to increase pipeline public awareness and the need to call if you smell gas.
- Support public awareness programs targeted at damage prevention and pipeline safety awareness.
- Use industry training facilities and evaluate opportunities to expand outreach/education programs to external stakeholders.
- Reach out to emergency responder community in order to enhance emergency response capabilities.
- Collaborate with stakeholders near existing transmission lines to increase awareness/adoption of appropriate PIPA recommended best practices.
- Conduct organizational response drills to improve emergency preparedness.
- Participate in state, regional and national multi-agency emergency response training exercises.
- Support industry participation in a mutual assistance program.
- Search for new and innovative ways to train, engage and provide appropriate feedback to stakeholders, including emergency responders, public officials, excavators, consumers, safety advocates, and the public living near pipelines.
- Educate the Pipeline Safety Trust and other public stakeholders on distribution and intrastate transmission pipelines, AGA and industry initiatives to improve pipeline safety, and receive input.
- Develop publications dedicated to improving safety and operations.

Pipeline Planning Engagement
- Build an active coalition of AGA member representatives to work with PHMSA and other stakeholders to implement PIPA recommended practices pertaining to encroachment around existing transmission pipelines.

Advancing Technology Development
- Support R&D investment, pilot testing and technology implementation.
- Work with PHMSA and other stakeholders on opportunities to increase R&D funding and deployment of technologies.
- Advocate to state commissions the inclusion of research funding in rate cases.
AGA’s Commitment to Enhancing Safety: Actions Completed

Building Pipelines for Safety
Construction
✓ Review and revise established construction procedures to provide for appropriate (risk-based) oversight of contractor installed pipeline facilities.
✓ Extend Operator Qualification to include tasks related to new main & service construction.
✓ Implement applicable portions of AGA’s technical guidance document, “Oversight of new construction tasks to ensure quality.”

Emergency Shutoff Valves
✓ Expand EFV installation beyond single family residential homes to small commercial and multi-family residential services.
✓ Begin risk-based evaluation on the use of automatic shutoff valves, remotely controlled valves or equivalent technology in HCAs.

Operating Pipelines Safely
Integrity Management
✓ Confirm the established Maximum Allowable Operating Pressure (MAOP) of transmission pipelines.
✓ Under DIMP, evaluate risk associated with trenchless pipeline techniques and implement initiatives to mitigate risks.
✓ Under DIMP, identify distribution assets where increased leak surveys may be appropriate.
✓ With PHMSA, create a Data Quality & Analysis Team to analyze data PHMSA collects, determine what the data is telling us, issue reports, identify missing information and how best to collect that data, and key metrics that indicate safety concerns.
✓ Implement a Data Alert Monitoring program and protection practices identified through AGA Gas Utility Best Practices Program.

Excavation Damage Prevention
✓ Implement applicable portions of AGA’s technical guidance, “Ways to improve engagement between operators & excavators.”

Physical and Cybersecurity/System Controls
✓ Create a DNG ISAC.
✓ Create a Cybersecurity Task Force to develop products and programs that strengthen cybersecurity.
✓ Conduct an all-hazard threat analysis and physical security benchmarking survey.
✓ Work with TSA to develop and implement Pipeline Security Guidelines.
✓ Create a Cybersecurity Assessment Program, including workshops that will allow industry to address their cybersecurity risks.
✓ Hold workshops and events: Workplace Violence Prevention & Insider Threats, SCADA, Control Room Management.

Enhancing Pipeline Safety
Safety Knowledge Sharing
✓ Create a voluntary AGA Peer Review Program that allows subject matter experts from gas utilities to review peer companies, identify areas that are working well and areas for potential improvement.
✓ Work with INGAA, API, AOP, Canadian Gas Association and Canadian Energy Pipeline Association on a comprehensive safety management study that explores initiatives currently utilized by other sectors and the pipeline industry.
✓ Create a Safety Information Resources Center for the sharing of safety information.
✓ Hold regular operations executives’ roundtables annually to discuss safety initiatives.
✓ Annually host roundtables focused on operator experience and lessons learned during the AGA Operations Conference.
✓ Develop guidance: To determine a distribution or transmission pipeline’s fitness for service and MAOP, and the critical records needed for that determination; For oversight of new construction tasks to ensure quality; For trenchless pipeline installations; That presents benefits and disadvantages of the installation of AVS/SCAV block valves on new, fully replaced and existing transmission pipelines; On intergenerational transfer of knowledge for Field Supervisors; Emergency response; Natural gas infrastructure physical security.

Workforce Development
✓ Annual AGA Executive Leadership Development Program.
✓ Annual Center for Energy Workforce Development (CEWD) Summits.
✓ Create an AGA Diversity & Inclusion Task Force.
✓ Participate in government/industry initiatives to foster workforce development, such as the Utility Workforce Advisory Council composed of the Departments of Energy, Defense, Labor, Veterans Affairs; AGA, Edison Electric Institute, Nuclear Energy Institute, National Rural Electric Cooperative Association, American Public Power Association, International Brotherhood of Electrical Workers, Utility Workers Union of America, and CEWD.

Public Awareness and Emergency Response
✓ Incorporate an Incident Command System (ICS) type of structure into emergency response protocols.
✓ Integrate applicable provisions of AGA’s emergency response white paper and checklist into emergency response procedures.
✓ Create a Safety Alert Notification System that will allow AGA or its members to quickly notify other AGA members of safety issues that require immediate attention.
✓ Develop an Emergency Planning Resource Center and a Mutual Assistance Database.
✓ Implement AGA discussion groups to address safety issues including technical training and knowledge transfer, material supply chain issues, DIMP implementation, Tsim risk models, Pipeline Safety Management Systems, pipeline safety/compliance/oversight, GPS/GIS and work management systems, contractor quality management, management of company standards, odorization, compressor operations, public awareness, end damage prevention.

Pipeline Planning Engagement
✓ Develop a task group comprised of AGA staff and members to work closely with Pipelines and Informed Planning Alliance (PIPA) to ensure AGA members are addressed in joint PIPA initiatives.

Advancing Technology Development
✓ Work with INGAA, research consortiums and other pipeline trade associations to provide the NTSB with a compilation of the progress that has been made in advancing in-line inspection technology.
The American Gas Association (AGA), founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 71 million residential, commercial and industrial natural gas customers in the U.S., of which almost 92 percent - more than 65 million customers - receive their gas from AGA members. Today, natural gas meets almost one-fourth of the United States’ energy needs.

In late June, the Pipeline and Hazardous Material Safety Administration (PHMSA) issued a flow chart reflecting its draft Integrity Verification Process (IVP) for gas transmission pipelines. AGA appreciates the conference call held by PHMSA staff in the weeks following publication to explain portions of the flow chart. In discussions with AGA, PHMSA staff acknowledged the flow chart is incomplete and was published with no supporting technical documents. Based upon preliminary review, AGA feels compelled to submit comments with the understanding that there will be an opportunity for PHMSA, the states, and other stakeholders to elaborate at and beyond the August 7, 2013 workshop. It is believed that the submission of these comments will help facilitate the workshop. AGA has the following observations and suggestions.

1. AGA’s member companies are deeply committed to pipeline safety and, more specifically, following the Congressional mandates included in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (hereafter called the Pipeline Safety Act). The Pipeline Safety Act requires operators to perform a one-time verification of MAOP records for transmission pipelines and to conduct pressure testing (or its
equivalent) on transmission pipelines in high consequence areas (HCAs) that have not been tested. AGA believes that the PHMSA draft IVP, if codified, would be in direct conflict with certain mandates in the Pipeline Safety Act.

2. The primary process path of the draft IVP appears to require cutting thousands of holes in gas transmission pipelines operating under pressure to collect coupons for material testing. This activity has risks to both the operator’s personnel and the public and should only be performed when there is a clearly defined and understood benefit.

3. The PHMSA draft IVP mixes the testing requirements of Subpart J Test Requirements and Subpart L Operations, with an expansion of the Integrity Management Program requirements in Subpart O Gas Transmission Pipeline Integrity Management. This creates a complex process that is operationally impractical. It is critical to keep these concepts separate.

AGA commends PHMSA for its efforts in enhancing pipeline safety. However, the complexity of the PHMSA draft IVP, and the reliance on unproven operating practices, has AGA concerned about the safety implications associated with the process.

To move the regulatory process forward in an expedited manner and implement the Congressional mandates in the Pipeline Safety Act, AGA has submitted herein suggested amended regulatory language to 49 CFR § 192.619 Maximum allowable operating pressure: Steel or plastic pipelines that provides for pressure testing, replacement, In-Line Inspection (ILI) testing, pressure reduction or abandonment of the nation’s gas transmission pipelines. The amendments to the regulation are straightforward, safe and effective. See Exhibit I. The proposed amendment leverages industry practices, PHMSA regulations and proven technology for validating the Maximum Allowable Operating Pressures (MAOP) of natural gas transmission pipelines. The language is written to follow the legislative mandates in the Pipeline Safety Act. AGA requests that PHMSA consider the language.

Detailed Comments

II. Amending 49 CFR § 192.619

There are four primary criteria used by pipeline operators in establishing MAOP of a natural gas transmission pipeline under the existing code: Design Pressure, Pressure Test, Historic
Operating Pressure and the Maximum Safe Pressure. The amended language that AGA is proposing builds upon the existing system and forces operators to comply with all of the additional testing requirements mandated in the Pipeline Safety Act section 23(d). The amended language allows the existing regulations for distribution pipelines which are also regulated by 49 CFR § 192.619 to remain unchanged.

The amended regulation would require a testing program that is comprehensive and takes into account the uniqueness of each transmission pipeline system. AGA recognizes that the proposed regulation will be very costly for intrastate pipeline operators, and that it will be necessary for the companies to submit implementation plans to its jurisdictional authority. PHMSA’s enabling statute establishes federal oversight of state pipeline safety programs. Therefore, PHMSA has the ability to implement oversight for the plans submitted to state regulatory agencies.

III. The legal Implications of the draft PHMSA IVP

PHMSA stated that the draft IVP “will help address several mandates set forth in Section 23, Maximum Allowable Operating Pressure, of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011”¹. AGA believes that implementing the draft IVP would be in conflict with several provisions of the Pipeline Safety Act. The law regarding agencies implementing federal statutes is settled.

_Chevron v. NRDC_ 467 U.S. 837 (1984), stated that, "When a court reviews an agency's construction of the statute which it administers, it is confronted with two questions." _467 U.S._, at 842. First, applying the ordinary tools of statutory construction, the court must determine "whether Congress has directly spoken to the precise question at issue. If the intent of Congress is clear, that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress." _Id._, at 842-843. But "if the statute is silent or ambiguous with respect to the specific issue, the question for the court is whether the agency's answer is based on a permissible construction of the statute." _Id._ at 843.

_Chevron_ is rooted in a background presumption of congressional intent: namely, "that Congress, when it left ambiguity in a statute" administered by an agency, "understood that the ambiguity would be resolved, first and foremost, by the agency, and desired the agency (rather than the courts) to possess whatever degree of discretion the ambiguity allows." _Smiley v. Citibank (South Dakota), N.A._, 517 U. S. 735, 740-741 (1996). _Chevron_ thus provides a stable background rule against which Congress can legislate: Statutory ambiguities will be resolved, within the bounds of reasonable interpretation, not by the courts but by the administering agency. See _Iowa Utilities Bd._, 525 U. S., at 397.

Congress knows to speak in plain terms when it wishes to circumscribe, and in capacious terms when it wishes to enlarge, agency discretion.²

There is nothing ambiguous in the Pipeline Safety Act of 2011. Congress was not circumscribed and did not speak in ambiguous terms. Congress referenced portions of 49 CFR 102 to ensure that their intent was clear. The relevant legislation stated, in part,

**SEC. 23. MAXIMUM ALLOWABLE OPERATING PRESSURE.**

“(d) TESTING REGULATIONS.—
“(1) IN GENERAL.—Not later than 18 months after the date of enactment of this section, the Secretary shall issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in high-consequence areas and operating at a pressure greater than 30 percent of specified minimum yield strength.
“(2) CONSIDERATIONS.—In developing the regulations, the Secretary shall consider safety testing methodologies, including, at a minimum—
“(A) pressure testing; and
“(B) other alternative methods, including in-line inspections, determined by the Secretary to be of equal or greater effectiveness.
“(3) COMPLETION OF TESTING.—The Secretary, in consultation with the Chairman of the Federal Energy Regulatory Commission and State regulators, as appropriate, shall establish timeframes for the completion of such testing that take into account potential consequences to public safety and the environment and that minimize costs and service disruptions.
“(e) HIGH-CONSEQUENCE AREA DEFINED.—In this section, the term ‘high-consequence area’ means an area described in section 60109(a).”.

Congress expressly stated that it wanted PHMSA to issue regulations for testing untested pipe by July 2013. Congress expressly stated that pressure testing or other equivalent methods, including ILL, could be used. Congress wanted the regulation to give priority to high consequence areas (HCAs). Congress also wanted to give priority to high stress pipelines above 30% Specified Minimum Yield Strength (SMYS).

**IV. AGA Study on Pressure Testing and Replacement**

AGA retained EN Engineering to perform an independent study with the objective of providing an analysis of the impacts increased testing requirements may have on AGA member companies, as well as the entire intrastate pipeline industry. AGA is submitting the *Evaluation of MAOP Testing for Transmission Pipelines* by EN Engineering concurrent with these comments. As part of this study, the options of testing, replacement and lowering operating pressure were reviewed. Review of nominal pipe diameters and class location of the data set

show a strong correlation between AGA companies that submitted the data and all pipelines classified as intrastate pipelines. Interstate pipeline companies have different operating and size characteristics and are excluded from any analysis in this study.

The study concludes that:

- For AGA companies, the estimated cost to complete MAOP testing in Class 3, 4 and HCA locations is $11.9 billion. If regulations mandate testing in all class locations, this cost increases to $24.7 billion.
- Extrapolation to all intrastate pipelines increases estimated costs to $23.0 billion for testing in class 3, 4 and HCA locations, and $49.6 billion for all class locations.
- Potential MAOP testing requirements will result in markedly significant impacts in terms of outage management, resource availability and system configuration. A carte blanche application, across all operators, of a standardized method for MAOP validation, cannot feasibly be implemented. Operators will need to work individually with each of their Commissions to determine the feasible plan for each affected pipeline, and engineering prioritization studies.³

In order to gauge the potential impacts to the industry, fifty-six (56) AGA member companies (52,444 transmission miles) provided advance data on their anticipated reporting for the calendar year 2012 PHMSA Transmission Annual Report. This report included information pertaining to:

Part K: Miles of Transmission Pipe by Specified Minimum Yield Strength.
Part Q: Gas Transmission Miles by §192.619 MAOP Determination Method.
Part R: Gas Transmission Miles by Pressure Test (PT) Range and Internal Inspection.

AGA members submitted the data in February 2013, and this data closely correlates to the data these companies submitted to PHMSA in June 2013.

V. The Technical Implication of the PHMSA Draft IVP
AGA will submit detailed comments after the PHMSA workshop on August 7th to address the technical implications raised by PHMSA’s draft IVP. A few concerns about the technical practicality of the process are highlighted below.

³ Evaluation of MAOP Testing for Transmission Pipelines by EN Engineering, June 20, 2013,
The first section of PHMSA’s draft IVP is labeled “Screen for Applicability Grandfather Clause and MAOP Records.” Steps one through five appear to mimic the MAOP method selection process used in 49 CFR §192.619. However, the draft IVP treats the MAOP methodologies completely different than PHMSA, state regulators and operators have applied the regulation for more than forty years. The PHMSA draft IVP treats pre-1970 and post-1970 records in an identical manner, while existing regulations have different record keeping requirements for pre-and post-1970 pipe. PHMSA’s draft IVP forces operators to have complete records in all MAOP method selection categories in §192.619(a)(1-4) and §192.619(c). Existing regulations require operators to compare the available information in the MAOP categories and used the appropriate information. A single record, such as a pressure test, is adequate for MAOP verification. Additionally, requiring complete records in all MAOP categories is inconsistent with existing regulation, operator practices, and PHMSA’s transmission and gathering annual report form Part Q that was created in 2012.

The section of the draft IVP that essentially all pipelines will be directed to follow on the decision tree is labeled “Material Documentation Process.” Historically, the overwhelming preference to determine the strength of pipe is via a pressure test. Operators use the pressure test procedures in 49 CFR 192 Subpart J for newly installed pipelines. The historic operating pressure to establish MAOP under 49 CFR §192.619(a)3 has also been used, and its use is only permitted when the historical pressure has demonstrated to be lower or equal to the MAOP calculated from design records or a pressure test. Testing the coupon tensile strength will provide information on the steel of the normal 20 foot pipe joint, but this method of material testing reveals nothing about girth welds, long seam welds, couplings, or the adjacent joint. This test method is already available in 49 CFR §192.107. Tensile strength testing per section II-D of Appendix B was considered as a least favored option, but the PHMSA draft IVP seems to treat it as a primary step in MAOP establishment. Operator personnel are trained to perform hot taps on pressurized pipelines. However, it is an operation that increases the potential for personal injury and should not be performed unnecessarily.

V. Conclusion

AGA commends PHMSA’s continuing commitment to pipeline safety and it appreciates the opportunity to comment on the PHMSA draft IVP. Safety is AGA’s number one priority and it welcomes honest, forthright public discussion to enhance safety. AGA has serious concerns
with the PHMSA draft IVP. There are legal and technical problems that make the draft IVP process overly complex and in some cases extremely difficult, if not impossible, to implement without compromising safety, reliability and efficiency.

To move the regulatory process forward, AGA has offered regulatory language that implements Congressional mandates, is consistent with PHMSA regulations, current industry practices, and uses proven technology. Some operators are already implementing the mandates in section 23(d) of the Pipeline Safety Act. These operators would suffer unnecessary and irreparable harm if PHMSA was to codify its IVP process, as proposed. AGA requests a critical analysis of the regulatory language that it has proposed to implement the testing provisions of the Pipeline Safety Act. Finally, AGA offers the EN Engineering report for the cost–benefit analysis that must be performed for rulemaking.

AGA is very open to working with PHMSA, its state partners, public representatives and other stakeholders on a way to meet the Congressional mandates and PHMSA’s goals. Our purpose is the same…the safe, reliable and efficient delivery of natural gas.

If you need additional information please feel free to contact me.

Respectfully submitted,

Date:

By:  

Christina Sames

For further information, please contact:

Christina Sames  
Vice President  
Operations and Engineering  
American Gas Association  
400 North Capitol Street, NW  
Washington, D.C. 20001  
(202) 824-7214  

csames@aga.org

Philip Bennett  
Senior Managing Counsel  
American Gas Association  
400 North Capitol Street, NW  
Washington, D.C. 20001  
(202) 824-7339  
pbennett@aga.org
AGA Proposed Regulatory Language: 192.619 (Note – Changes of note are in paragraph e)

§192.619 What is the maximum allowable operating pressure for steel or plastic pipelines?

(a) Except as provided in paragraph (c) of this section, no person may operate a segment of steel or plastic pipeline at a pressure that exceeds the lowest of the following:

1. The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:
   
   (i) Eighty percent of the first test pressure that produces yield under section NS of Appendix N of ASME B31.8 (incorporated by reference, see §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

   (ii) If the pipe is 12½ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa) gage.

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

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

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


<table>
<thead>
<tr>
<th>Class location</th>
<th>Installed before Nov. 12, 1970</th>
<th>Installed after Nov. 11, 1970</th>
<th>Covered under §192.14</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.1</td>
<td>1.1</td>
<td>1.25</td>
</tr>
<tr>
<td>2</td>
<td>1.25</td>
<td>1.25</td>
<td>1.25</td>
</tr>
<tr>
<td>3</td>
<td>1.4</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td>4</td>
<td>1.4</td>
<td>1.5</td>
<td>1.5</td>
</tr>
</tbody>
</table>

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

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

<table>
<thead>
<tr>
<th>Pipeline segment</th>
<th>Pressure date</th>
<th>Test date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006. Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.</td>
<td>March 15, 2006, or date line becomes subject to this part, whichever is later.</td>
<td>5 years preceding applicable date in second column.</td>
</tr>
</tbody>
</table>
(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

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

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

(e) Transmission pipelines operating greater than 30% SMYS in HCAs:

(1) For transmission pipelines located in HCAs with a MAOP that produces a hoop stress of greater than or equal to 30% of SMYS and that have not been previously tested, the pipeline must be subjected to one of the following tests;

   (i) a pressure test consistent with the requirements of section a(2),

   (ii) an in-line inspection,

   (iii) a reduction in pipeline MAOP by 20%, or

   (iv) a procedure that has been approved by the Administrator.

(2), the operator shall within 12 months of this final rule, submit a plan (not to exceed xxx years in duration) to the authorities having safety and ratemaking jurisdiction to test the segment according to one of the methods in (e)(1) above. Post construction pressure tests will be conducted in accordance with Part 192, Subpart J.

Note: The language maintains the existing grandfathering for all distribution pipe and transmission pipe below 30% SMYS. It gives four options for pipe above 30% to comply with MAOP existing pressure tests, new subpart J pressure tests, in-line inspection that confirms the design MAOP.

No deadline has been established for completing the tests because more information is needed from individual operator engineering analysis.
Evaluation of MAOP Testing for In-Service Transmission Pipelines

Prepared for:

American Gas Association

Prepared by:

EN Engineering

June 20, 2013
Notice and Disclaimer

The work associated with this project has been performed by EN Engineering with funding from the American Gas Association (AGA).

This report addresses general cost analyses, timelines and potential barriers related to MAOP testing of in-service transmission pipelines and transmission pipeline replacement projects. It was not intended for this study to provide detailed engineering project analysis related to costs and timelines, but rather broad ranges in order to provide an order of magnitude. Cost estimates herein are based on a preliminary analysis and are contingent on numerous variables specific to a particular operator, including, but not limited to, state and federal regulatory requirements, macro-economic market conditions, geographic area and system infrastructures.

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<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AGA</td>
<td>American Gas Association</td>
</tr>
<tr>
<td>BLM</td>
<td>Bureau of Land Management</td>
</tr>
<tr>
<td>CFR</td>
<td>Code of Federal Regulations</td>
</tr>
<tr>
<td>CNG</td>
<td>Compressed Natural Gas</td>
</tr>
<tr>
<td>CPUC</td>
<td>California Public Utilities Commission</td>
</tr>
<tr>
<td>EPA</td>
<td>Environmental Protection Agency</td>
</tr>
<tr>
<td>HCA</td>
<td>High Consequence Area</td>
</tr>
<tr>
<td>HDD</td>
<td>Horizontal Directional Drilling</td>
</tr>
<tr>
<td>ILI</td>
<td>In-line Inspection</td>
</tr>
<tr>
<td>LDC</td>
<td>Local Distribution Company</td>
</tr>
<tr>
<td>LNG</td>
<td>Liquefied Natural Gas</td>
</tr>
<tr>
<td>MAOP</td>
<td>Maximum Allowable Operating Pressure</td>
</tr>
<tr>
<td>NTSB</td>
<td>National Transportation Safety Board</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>Operations and Maintenance</td>
</tr>
<tr>
<td>PHMSA</td>
<td>Pipeline and Hazardous Materials Safety Administration</td>
</tr>
<tr>
<td>PIR</td>
<td>Potential Impact Radius</td>
</tr>
<tr>
<td>PSA 2011</td>
<td>Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011</td>
</tr>
<tr>
<td>PT</td>
<td>Pressure Test</td>
</tr>
<tr>
<td>ROW</td>
<td>Right-of-Way</td>
</tr>
<tr>
<td>SMYS</td>
<td>Specified Minimum Yield Strength</td>
</tr>
<tr>
<td>TIMP</td>
<td>Transmission Integrity Management Plan</td>
</tr>
<tr>
<td>TVC</td>
<td>Traceable, Verifiable and Complete</td>
</tr>
</tbody>
</table>
1.0 EXECUTIVE SUMMARY

As a result of a number of pipeline incidents over the past several years, the Pipeline Hazardous Materials Safety Administration (PHMSA) is considering whether or not transmission pipelines with no prior pressure test should be pressure tested to confirm the currently established Maximum Allowable Operating Pressure (MAOP) and whether or not pressure testing should be performed to a minimum of 1.25 times MAOP. Additionally, PHMSA will be developing future rulemaking to address cases where transmission pipeline operators have records that are insufficient to confirm the established MAOP in Class 3, Class 4 and Class 1 and 2 HCA locations.

Until firm rulemaking is established and released, the ramifications are unknown. However, various mandates and recommendations from entities such as PHMSA, the National Transportation Safety Board (NTSB) and the California Public Utility Commission have provided some indication of what future rulemaking might contain.

The American Gas Association (AGA) retained EN Engineering to perform a study with the objective of providing analysis on the impacts increased testing requirements may have on the industry as a whole. As part of this study, the options of testing, replacement and lowering operating pressure of in-service transmission pipelines were reviewed.

In order to gauge the potential impacts to the industry, fifty-six (56) AGA member companies (52,444 transmission miles) provided advance data on their anticipated reporting for the calendar year 2012 PHMSA Transmission Annual Report which included information pertaining to:

- Part K: Miles of Transmission Pipe by Specified Minimum Yield Strength.
- Part Q: Gas Transmission Miles by §192.619 MAOP Determination Method.
- Part R: Gas Transmission Miles by Pressure Test (PT) Range and Internal Inspection.

Records

To date, the industry has been generally successful at confirming MAOP based on records for Class 3, 4 and Class 1 and 2 High Consequence Areas (HCA). Preliminary data from AGA member companies suggests for those areas reviewed, approximately 87% meet the “traceable, verifiable and complete” criteria for the MAOP determination method utilized.

Impact of Additional Testing Requirements

If regulations are expanded to require testing on previously untested lines, the impact to industry will be significantly greater than that related to testing lines with incomplete records. Data suggests:

- 32% of the respondent transmission mileage will be subject to additional testing if MAOP determination methodologies related to historic operating pressures, §192.619(a)(3) and §192.619(c), are removed from federal pipeline code.
- 9% of the respondent mileage will be subject to additional testing if §192.619(c), the "grandfather clause", is removed from federal pipeline code.
- 34% of the respondent mileage could be subject to additional testing if future rulemaking requires testing up to 1.25 times MAOP, including within Class 1 locations.

**Configuration**

Typically, it is not feasible to remove pipe from service for pressure testing if the line is a single source feed, or if system capacity requirements preclude interruption of service. Based on discussions with several AGA member companies, the following percentages of pipe infrastructure cannot be removed from service for the pressure tests:

- 31% of pipe with less than a 1.25 times MAOP pressure test or no documented pressure test.
- 4% of pipe with a pressure test greater than 1.1 times MAOP but less than 1.25 times MAOP.
- 42% of pipe with a pressure test less than a 1.1 times MAOP or no documented pressure test.

Comparisons of the distributions of pipe size and of class location show a strong correlation between AGA member company transmission lines and all pipelines classified as intrastate pipeline. Interstate companies have different operating and size characteristics and are excluded from any analysis in this study.

**Cost Estimates**

Scenario-based cost estimates were developed to project the potential cost impact to operators in the United States:

- For all AGA companies, the estimated cost to complete MAOP testing for in-service gas transmission pipelines in Class 3, 4 and HCA locations is $11.9 billion. If regulations mandate testing in all class locations, this cost increases to $24.7 billion.
- Extrapolation to all intrastate pipelines increases estimated costs from $23.0 billion to $49.6 billion respectively.

**Barriers**

Individual surveys and focused discussions were conducted with select operator companies and service providers to gage their impression of areas that could be significantly impacted by increased testing requirements. Impacts to the industry as a result of increased requirements include:

- Current workforce levels will need to expand to support current pipeline safety programs as well as significant additional testing requirements. The availability of experienced contractors will be an issue.
- Permitting can significantly lengthen the overall life cycle of a testing or replacement project.
- The occurrence of failures during a testing project can be unpredictable.
- The existing configuration of a pipeline has a substantial effect on the scope, duration, and cost of a hydrostatic test project.
• Single source pipelines and/or peak customers for whom the operator's system will be unable to supply gas, or an adequate amount of gas, while a section of pipeline is tested may require a large volume of temporary gas supply.

• Addressing transmission lines which are geographically and operationally influenced by the locale and operational characteristics of the supplied distribution systems.

• Testing and replacement concentrated on "shoulder months" result in a lengthening of the duration of an operator’s expanded MAOP testing plans and increased logistical constraints to complete.

• Ratepayer advocacy groups objecting to the higher cost alternative of pipe replacement.

• Population related development in the immediate proximity of rights-of-way and/or infrastructure may limit the availability of alignments for replacement projects.

• If the industry mobilizes a large number of replacement projects in a short time frame, the availability of materials for infrastructure such as line pipe and valves, may become limited.

Conclusions

Specific regulation changes for the remainder of the country are unknown at this time, but the expansion of regulations will have a considerable effect to the industry. While the specific relationships of scope and costs are difficult to assess, the expansion of regulations in California has resulted in additional costs resulting from testing and replacement of in-service transmission pipelines. Actual costs will be driven by the specific testing and timeline mandates implemented by PHMSA and state jurisdictional authorities. Potential MAOP testing requirements will result in markedly significant impacts in terms of outage management, resource availability and system configuration. A carte blanche application across all operators in a short time frame of a standardized method for MAOP testing will require extraordinary resources.
2.0 INTRODUCTION

2.1. Background

As a result of a number of pipeline incidents over the past several years, the Pipeline Hazardous Materials Safety Administration (PHMSA) is considering whether transmission pipelines with no prior pressure test should be pressure tested to confirm the currently established MAOP. Additionally, PHMSA will be developing future rulemaking to addresses cases where transmission pipeline operators have records that are insufficient to confirm the established MAOP in Class 3, Class 4 and Class 1 and 2 HCA locations.

Until firm rulemaking is established and released, the ramifications are unknown. However, various mandates and recommendations, such as those discussed in the subparagraphs below, have provided some indication as to options PHMSA may be considering.

2.1.1. Pipeline Safety Reauthorization

On January 3, 2012, the “Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011” (PSA 2011) was signed into law. Amongst the various mandates was section number 23 on Maximum Allowable Operating Pressure. In short, this section required each owner or operator of a pipeline facility to:

- Conduct a verification of pipeline records for transmission pipelines located in a Class 3, and Class 4 locations and Class 1 and 2 HCAs to verify that records confirm the established MAOP.

- Identify and submit information indicating where records are insufficient to confirm the established MAOP.

Additionally, the section required the Secretary of Transportation to:

- For those lines where records were unable to verify the established MAOP, require the owner or operator to reconfirm the MAOP as expeditiously and economically as feasible.

- Determine the actions that are appropriate for a pipeline owner or operator to take in order to maintain pipeline safety until the MAOP is confirmed.

- Issue regulations for conducting tests to confirm the material strength of previously untested transmission pipelines located in an HCA and operating at a pressure greater than 30% of the specific minimum yield strength.

As a result of PSA 2011, pipeline operators have been working to review and confirm records to support the established MAOP.
2.1.2. **NTSB Recommendations**

As a result of the San Bruno incident, the National Transportation Safety Board (NTSB) issued multiple Safety Recommendations, including these to PHMSA\(^1\):

- Amend Title 49 Code of Federal Regulations §192.619 to delete the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test. (P-11-14)

- Amend Title 49 Code of Federal Regulations Part 192 of the Federal pipeline safety regulations so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the maximum allowable operating pressure. (P-11-15)

- Require that all natural gas transmission pipelines be configured so as to accommodate in-line inspection tools, with priority given to older pipelines. (P-11-17)

2.1.3. **PHMSA Reporting**

As a result of PSA 2011 and recommendations from the NTSB, PHMSA modified Form F7100.2-1 "Annual Report for Calendar Year 2012 Natural and Other Gas Transmission and Gathering Pipeline Systems" (Gas Transmission Annual Report) in order to collect additional information from operators to use during the development of future rulemaking.

Modifications to the Gas Transmission Annual Report included:

- Modifications to Part K: Miles of Transmission Pipe by Specified Minimum Yield Strength.

- The addition of Part Q: Gas Transmission Miles by §192.619 MAOP Determination Method.

- The addition of Part R: Gas Transmission Miles by Pressure Test (PT) Range and Internal Inspection.

2.1.4. **California Operator Mandates**

In addition to mandates and changes at the federal level, the state of California has superseded federal regulations by issuing various rulemakings and decisions to pipeline operators within the state of California. Amongst those issued, in June of 2011, the California Public Utility Commission (CPUC) issued decision 11-06-017 which ordered all California natural gas operators to develop and file a comprehensive pressure testing plan.

---

\(^1\) "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno California September 9, 2010"; National Transportation Safety Board
2.2. **Study Scope and Objectives**

In order to help the AGA and member companies understand the potential impact increased testing requirements could have on member companies, the AGA sought qualified firms to perform an engineering study. This report was prepared in response to the AGA request for an evaluation of MAOP testing inside and outside of High Consequence Areas.

This report addresses the following request from AGA:

- **Item 1:** Document cost estimates for MAOP hydrotesting and/or replacement of Class 1 and 2 HCA transmission pipe and Class 3 and 4 transmission pipe. This study should also attempt to conduct an analysis of pipe outside of HCAs that has not undergone MAOP testing.

- **Item 2:** Discuss timelines for scheduling pressure tests and replacement using sound engineering-based assumptions and empirical data.

- **Item 3:** Incorporate the list of permits necessary for various engineering projects and the costs and timeframes for each to be obtained.

- **Item 4:** List the barriers an operator would encounter when undergoing pressure tests and outline the potential costs associated with overcoming these issues.

- **Item 5:** Look at resource availability (i.e. the number of contractors with sufficient skill to assist the operator in pressure testing operations and pipe replacement) and identify operational bottlenecks if multiple operators are conducting tests simultaneously.

- **Item 6:** Outline the barriers to simply “extrapolating” the California Plan.

- **Item 7:** Discuss potential conflict between potential regulatory requirements to expand 49 CFR Subpart O assessments outside HCAs at the same time as untested pipe inside and outside of HCAs is pressure tested.

2.3. **Study Terminology**

Throughout the course of this study, several key terms are utilized as defined below:

- **MAOP Record Verification:** The use of records that accurately reflect the physical and operational characteristics of the pipeline (i.e. design, pressure test, pressure history and other operating information). The records should be traceable, verifiable and complete.

- **MAOP Confirmation:** Reconfirming the MAOP established using existing methods in §192.619.

- **MAOP Testing:** Congressional mandate of certain untested pipe to undergo a material strength test (usually hydrotesting) or an alternative testing method such as specialized internal inspection, regardless of whether records are traceable, verifiable, or complete.
3.0 ANALYSIS OF PHMSA REPORTING DATA

3.1. Data from AGA Member Companies

3.1.1. Background

EN Engineering worked in conjunction with the AGA to obtain preliminary representative data and information pertaining to the calendar year 2012 Gas Transmission Annual Report, specifically parts K, Q and R, from AGA member companies representing over fifty thousand transmission miles. It was acknowledged that at the time of the AGA survey, operators were still undergoing record validation efforts and actual numbers reported to PHMSA (due by June 15, 2013) could potentially vary. However, it was agreed by all parties that these numbers presented a reasonable representation of what would actually be submitted to PHMSA.

In December 2012 the AGA sent surveys to member companies soliciting information pertaining to the following sections of the Gas Transmission Annual Report for calendar year 2012:

- Part K: Miles of Transmission Pipe by Specified Minimum Yield Strength.
- Part Q: Gas Transmission Miles by §192.619 MAOP Determination Method.
- Part R: Gas Transmission Miles by Pressure Test (PT) Range and Internal Inspection.

3.1.2. Survey Response

The AGA obtained information back from 56 member companies which represented 52,444 transmission miles, with the majority being intrastate mileage. Approximately 8,800 miles of the total reported mileage is considered interstate.

Due to data and reporting discrepancies, responses from two (2) member companies were not considered; however, in portions of the study, particularly cost analysis scenarios, characterizations based on 54 company responses were applied to these two (2) companies in an effort to provide analysis reflecting all member companies contributing to the study.

In the analysis of data pertaining to MAOP determination method (see section 3.2 and 3.3), data from eight (8) member companies was not considered due to discrepancies in the reported data.

3.1.3. Focused Discussions with Operators

In addition to the operator surveys, focused discussions with three (3) operators with assets within the state of California, as well as five (5) operators with assets outside the state of California were held. The objectives of these discussions included:

- Understanding timelines, schedules, cost variations and implementation results for MAOP testing projects.
• Identify anticipated barriers to increased testing requirements.
• Calibrate assumptions and estimates made during the study.

The non-California companies were selected to represent the AGA membership as a whole. The California operators were interviewed to capture any additional insight derived from the implementation of their MAOP testing plans. Interviewed companies varied in geographic region, operational environment, system size, and amount of transmission pipe that has not been pressure tested to 1.25 times MAOP.

3.2. Incomplete Records

Item 23(c) in PSA 2011 mandates that the Secretary of Transportation require pipeline operators to reconfirm MAOP for those lines where records were unable to reconfirm the established MAOP.

Part Q of the AGA survey asked operators to provide information pertaining to incomplete records in Class 3, Class 4, Class 3 and 4 HCA and Class 1 and 2 HCA locations. Figure 1, derived from preliminary data provided by AGA survey respondents, shows the breakdown of incomplete records based on miles and class location.

![Figure 1: Percentage of Miles with Incomplete Records by Class / HCA Location](image)

For the purposes of this study, EN Engineering assumes that any future requirements related to the testing of locations with incomplete records will be encompassed by larger scale issues such as deleting §192.619(a)(3) and §192.619(c) from federal pipeline code. As a result, statistics and analysis specific to implications related to the MAOP testing of locations with incomplete records are not formally identified as a subset in this study.

3.3. Miles by MAOP Determination Method

In Safety Recommendation P-11-14, the NTSB is essentially recommending that PHMSA amend pipeline safety code to eliminate the “grandfather clause”. For the purposes of this analysis, EN Engineering is considering the “grandfather clause” to be both §192.619(a)(3) and §192.619(c) of 49 CFR Part 192. Technically, §192.619(c) is the “grandfather clause”
and addresses pre-code (prior to November 12, 1970) pipe on a stand-alone basis. However, similar language was placed into §192.619(a) in order to compare historic operations against the other MAOP determination methods, in the event, for example the §192.619(a)(1) calculation for that particular line is higher than this pre-1970 operating pressure, thus ensuring §192.619(a)(3) would be the limiting factor. As a result, any revisions to code in terms of the “grandfather clause” could affect both sections of code.

Part Q of the AGA survey requested information pertaining to the subsection of §192.619 serving as the limiting factor for establishing MAOP. Of particular significance, this provided information on the potential population of miles subject to the “grandfather clause”.

**Figure 2** graphically illustrates the number of transmission miles by MAOP determination method for 48 respondent AGA member companies. As discussed previously in section 3.1.2, due to discrepancies across the various parts of the survey, data from eight (8) respondent companies was not included in this analysis.

![Figure 2: Gas Transmission Miles by §192.619 MAOP Determination Method](image)

While pressure test was reported as the MAOP determination method for the majority of mileage, a significant portion (32%) of the respondent mileage has established MAOP by historic operating pressure, and will be affected if these methodologies are removed from federal pipeline code. By strict interpretation of the “grandfather clause”, if §192.619(c) is removed from federal pipeline code, 9% of the respondent mileage will be affected.

### 3.4. Miles by Class Location and HCA

PSA 2011 and NTSB reports include recommendations and mandates specific to HCAs and certain class locations. Parts Q and R from the AGA survey provide information related to HCAs and class locations, which is presented in **Figure 3**.
Based on the data, approximately 23% of the mileage operated by the AGA survey respondents is in an urban, heavily congested area.

49 CFR Part 192 Subpart O was designed to incorporate population density as well as operating characteristics (i.e. diameter, pressure) for a specific pipe section to evaluate risk. Using a prescribed equation, the Potential Impact Radius (PIR) was calculated by pipeline operators and smaller diameter, lower pressure pipelines typically did not create an HCA. Based on the survey data, approximately 43% of the Class 3 and 4 mileage is considered non-HCA. Although per Subpart O non-HCAs are considered a lower risk, Class 3 and 4 non-HCAs are not distinguished as a lower risk in any of the various safety recommendations addressed in this report.

3.5. Miles by Pressure Test Range

In Safety Recommendation P-11-15, the NTSB recommended that PHMSA amend Title 49 of the Code of Federal Regulations to essentially require pipeline transmission operators to perform a pressure test to at least 1.25 times MAOP. Current federal pipeline regulations (49 CFR §192.619) require that pipelines installed after November 11, 1970 have a post-construction pressure test with a test factor commensurate with class location as indicated in the table below:

---

2 Table adapted from 49 CFR Part 192 §192.619(a)(2)(i)
Table 1: Pressure Test Factors

<table>
<thead>
<tr>
<th>Class Location</th>
<th>Test Pressure Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.1</td>
</tr>
<tr>
<td>2</td>
<td>1.25</td>
</tr>
<tr>
<td>3</td>
<td>1.5</td>
</tr>
<tr>
<td>4</td>
<td>1.5</td>
</tr>
</tbody>
</table>

As noted in the table above, current regulations allow a safety factor in Class 1 locations that is less than the safety factor recommended by the NTSB. As a result, any changes to regulations resulting from NTSB Safety Recommendation P-11-15 will primarily affect pipelines located in Class 1 areas, but will also affect lines in all class locations with insufficient testing records.

Part R of the AGA survey asked operators for information pertaining to the miles of transmission pipe with:

- A pressure test greater than or equal to 1.25 times MAOP.
- A pressure test between 1.1 and 1.25 times MAOP.
- No documented pressure test or a pressure test less than 1.1 times MAOP.

Figure 4 represents the data as reported by 54 AGA member companies.

![Miles by Pressure Test Range](image)

**Figure 4: Miles by Pressure Test Range**

As indicated by the graphic, approximately two thirds of the respondent mileage has been subject to a pressure test of at least 1.25 times MAOP.

Based on this data population and dependent upon the outcome of future rulemakings:

- 34% of the respondent mileage could be subject to additional testing if future rulemaking requires testing of in-service transmission lines up to 1.25 times MAOP for all class locations.
The graphic below further breaks down Figure 4 to include class locations in each of the three pressure test ranges.

![Figure 5: Miles by Pressure Test Range and Class / HCA](image)

Additional observations from this data population include:

- 18.5% of pipe with a less than 1.25 times MAOP pressure test or no documented pressure test is located in Class 3, 4 or a Class 1 or 2 HCA.
- 21.6% of pipe with a less than 1.1 times MAOP pressure test or no documented pressure test is located in Class 3, 4 or a Class 1 or 2 HCA.

3.6. **Companies with Pressure Test Less than 1.25 times MAOP or No Documented PT**

The transmission systems for 42 of the 54 AGA member companies in the data population contain pipe that has been pressure tested to less than 1.25 times MAOP, with twelve (12) companies having no transmission pipe that has been tested to less than 1.25 times MAOP and one (1) company having 100% of their transmission pipe being tested to less than 1.25 times MAOP.

The twelve (12) companies with no miles of transmission pipe potentially requiring MAOP testing each operate less than 260 miles of transmission pipe and seven (7) of these operate less than 50 miles of transmission pipe. **Figure 6** contains a histogram that shows the distribution of company transmission systems that have been pressure tested to less than 1.25 times MAOP or have no documented pressure test.
3.7. Ability for Internal Inspection

In Safety Recommendation P-11-17, the NTSB recommended that PHMSA require all gas transmission pipelines be configured to accommodate in-line inspection (ILI) tools. As part of the revised Gas Transmission Annual Report for calendar year 2012, PHMSA added Part R in order to gather information on the ability to inspect pipelines using ILI tools.

Per the annual report instructions, PHMSA considers “internal inspection able” to mean “a length of pipeline through which commercially available devices can travel, inspect the entire circumference and wall thickness of the pipe, and record or transmit inspection data in sufficient detail for further evaluation of anomalies”.3

The table below presents the information reported by 54 of the AGA respondents. Based on this information, more than 60% of the respondent mileage is considered ILI-able. Approximately 69% of the pipe that has been pressure tested to less than 1.25 times MAOP or not pressure tested is considered ILI-able.

---
3 Instructions (rev 12-2012) for Form PHMSA F 7100.2-1 (rev 12-2012); page 18
3.8. **Ability to Remove a Section of Pipe from Service**

In some cases, it may not be feasible to remove pipe from service to complete a pressure test for the following reasons:

- Single source feed for a town, distribution center, or an industrial customer.
- System capacity requirements.

As a part of the focused discussions with select operating companies, a second survey was issued to those companies in an effort to collect additional information about their specific pipeline systems and to drill deeper into the data submitted during the original survey. Five (5) companies participated in this effort, representing approximately 20% of the pipe reported by the 54 AGA company respondents that has not been pressure tested to 1.25 times MAOP. Data gleaned from the survey results and operator discussions indicates the following percentages of pipe infrastructure cannot be removed from service for the pressure tests:

- 31% of pipe with less than a 1.25 times MAOP pressure test or no documented pressure test.
- 4% of pipe with a pressure test greater than 1.1 times MAOP but less than 1.25 times MAOP.
- 42% of pipe with a pressure test less than a 1.1 times MAOP or no documented pressure test.

3.9. **Summary of Key Statistics**

Information gathered from the survey responses for the AGA member companies is the foundation for this study and is utilized and referenced throughout the report. Below is a summary of key data and characterizations:

- 32% of the respondent transmission mileage will be subject to additional testing if MAOP determination methodologies related to historic operating pressures, §192.619(a)(3) and §192.619(c), are removed from federal pipeline code.
• 9% of the respondent mileage will be subject to additional testing if §192.619(c), the “grandfather clause”, is removed from federal pipeline code.

• 34% of the respondent mileage could be subject to additional testing if future rulemaking requires testing of in-service transmission lines up to 1.25 times MAOP for all class locations.

• 18.5% of pipe with a less than 1.25 times MAOP pressure test or no documented pressure test is located in Class 3, 4 or a Class 1 or 2 HCA locations.

• 21.6% of pipe with a less than 1.1 times MAOP pressure test or no documented pressure test is located in Class 3, 4 or a Class 1 or 2 HCA.

• 31% of pipe with less than a 1.25 times MAOP pressure test or no documented pressure test cannot be removed from service.

• 4% of pipe with a pressure test greater than 1.1 times MAOP but less than 1.25 times MAOP cannot be removed from service.

• 42% of pipe with a less than 1.1 times MAOP pressure test or no documented pressure test cannot be removed from service.
4.0 MAOP TESTING OPTIONS

Although other viable options exist for the confirmation of MAOP, the scope of this study focuses on:

- Strength testing
- Pipe replacement
- Lowering operating pressure

Strength testing, often the most cost effective of this subset of options for establishing MAOP, may be the initial choice of an operator, but the implementation of such testing may encounter various challenges as discussed further in this report, and pipe replacement or lowering operating pressure may become more feasible options.

4.1. Testing

A pressure test involves shutting in a pipeline and pressurizing it with a test medium to a specified minimum pressure for an extended length of time. Subpart J of federal pipeline code allows for pressure tests to be performed with natural gas, air, inert gas, or water. Typically pressure testing on transmission piping operating at greater than 30% SMYS is performed using water. For the purposes of this study, testing refers to hydrostatic testing, which is a subset of strength testing.

During a hydrostatic testing project for in-service transmission pipelines, the section of the pipeline that is being tested is taken out of service for the duration of the construction portion of the project. The length of time that the pipeline is out of service may vary from one (1) month to three (3) or more months depending on the scope of work required to prepare the pipe for testing. The actual test is a relatively short duration event (approximately eight hours). Planning, pipe modifications, permitting, etc. can be logistically complicated and extend the project timeframe.

4.2. Pipe Replacement

Pipeline replacement involves installing a new main that will provide service to an area of the system that is currently supplied by a pipeline that has not been pressure tested to the required pressure level. Depending on land and system constraints, the replacement line could be installed adjacent to the current pipeline in a parallel right-of-way or in a new location. The replacement pipeline is installed following modern design and construction standards and in conformance with current regulatory requirements. As part of modern construction practices and regulatory requirements a precommission pressure test is performed to establish the required safety factor.

During construction of the replacement pipeline the existing pipeline can remain in-service. This is beneficial for single source / peak pipelines that cannot be taken out of service or may require a large amount of temporary gas supply to ensure continuous operation.

Another benefit of main replacement is that the installation is performed using modern steel/pipe and coating systems.
4.3. **Lowering Operating Pressure**

Lowering operating pressure involves decreasing the MAOP of a pipeline to a pressure level with a margin of safety lower than the pressure level the pipe previously operated at. When using this method, a company is treating the documented operating pressure on the pipeline as the pressure test. The new maximum operating stress on the pipeline is a margin of safety (1.25 minimum) lower than the maximum stress that the pipeline has experienced in operation. The pipeline at its new operating pressure has a safety factor equivalent to a pipeline that was pressure tested to 1.25 times the MAOP. From a system integrity and risk management perspective, lowering the operating pressure, using the method discussed in this section, is equally as beneficial as performing a pressure test to 1.25 times MAOP.

**Example of Lowering Pressure:**

*Current MAOP: 1000 psig*

*Documented Operating Pressure: 970 psig*

*Revised MAOP = 970 psig / 1.25 Safety Factor = 776 psig*

Lowering of operating pressure has significantly lower direct construction costs than either hydrostatic testing or main replacement. However, lowering pressure reduces system capacity and potentially causes long term operational restrictions that the other options do not create. Depending on the system design and capacity requirements, a new pipeline may be required to account for the capacity loss, causing the costs to approach those of replacement.
5.0 COST ANALYSIS

5.1 Data Correlations

5.1.1 Background

As part of this study, PHMSA transmission annual report data was reviewed and comparisons were made in order to understand if various categorizations applied to the AGA respondent companies could be extrapolated to the entire intrastate population and the transmission population (intrastate and interstate).

5.1.2 Data Set Comparison – Nominal Pipe Size

Based on information reported to PHMSA by operators on the calendar year 2011 Transmission Annual Report, the entire population of intrastate transmission lines is comprised of approximately 108,000 miles, largely driven by the large mileage of intrastate lines operated by midstream pipeline operators. The data population for the 56 AGA respondent companies is based on data provided as a result of the AGA survey, as well as information reported to PHMSA on the Transmission Annual Report. Approximately 8,800 miles of the total population (52,444 miles) of AGA respondent mileage are interstate miles which are included in the AGA respondent data set.

Figure 8 represents nominal pipe size groupings by percentage of the total population as reported in the AGA survey and to PHMSA by the 56 AGA respondent companies and intrastate pipeline operators, respectively. As illustrated, the distribution of pipe size versus the percentage of the total population is similar for both data sets.

---

Figure 8: AGA Respondent and Intrastate Comparison – Nominal Pipe Size

Figure 9 represents the same information as presented in Figure 8, with the addition of the pipe size distribution for the interstate pipeline operators. The data indicates that the interstate pipelines are an independent data set due to the distribution of pipe sizes across the population, primarily driven by the large distribution of pipe greater than 20-inches as compared to the AGA respondent companies and the intrastate population.

Figure 9: AGA Respondent, Intrastate and Interstate Comparison – Nominal Pipe Size
5.1.3. **Data Set Comparison – Class Location**

**Figure 10** shows the distribution of class location by the percentage of the total population for both AGA respondent mileage and intrastate transmission mileage as obtained from the PHMSA website. As indicated in the chart, the class distribution of pipe is similar for both data sets.

![Figure 10: AGA Respondent and Intrastate Comparison – Class Location](image)

**Figure 11** represents the same information as presented in **Figure 10** with the addition of the class location distribution for the interstate pipeline operators. The data indicates that the interstate pipelines are an independent data set due to the distribution of pipe across class locations, primarily driven by a higher percentage of line traversing rural areas.

![Figure 11: AGA, Intrastate, Interstate Comparison – Class Location](image)

Since the interstate transmission mileage is an independent data set, cost analyses presented in the following sections were performed for the AGA respondent mileage and the total intrastate transmission mileage only.
5.2. Regional Variations to Construction Costs

In 2011, the Oil and Gas Journal published a study on various regional construction costs which indicated that construction costs, particularly for labor, rights-of-way and miscellaneous factors, vary by region of the United States\(^5\). For this study, miscellaneous factors include items such as engineering, supervision and surveying.

**Figure 12** summarizes the regional cost factors derived from the study. Since this study was based on FERC project data from 1992 to 2008, cost impacts resulting from industry impacts such as recent large construction projects and recent failures are not reflected.

![Regional Construction Costs](image)

Cost factors will be utilized and discussed further later in this report when presenting regional cost estimates.

5.3. Regional Pipe and Nominal Pipe Size Distribution

5.3.1. 56 Responding AGA Member Companies

The regional pipe size distribution for the 56 member companies that responded to the initial AGA survey was compiled using 2011 PHMSA Transmission Annual Report data\(^6\). Approximately 8,800 miles included in this data are classified as interstate miles. The pipe size distribution for the 56 companies is shown by region in **Table 2**.

---


Table 2: Regional Pipe Size Distribution – 56 Reporting AGA Member Companies

<table>
<thead>
<tr>
<th>Region</th>
<th>&lt;6”</th>
<th>6/8”</th>
<th>10/12/14”</th>
<th>16/18/20”</th>
<th>22/24”</th>
<th>26/30”</th>
<th>34/36”</th>
<th>≥40”</th>
<th>Total Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central</td>
<td>21%</td>
<td>30%</td>
<td>16%</td>
<td>22%</td>
<td>2%</td>
<td>9%</td>
<td>0%</td>
<td>0%</td>
<td>10,307</td>
</tr>
<tr>
<td>Northeast</td>
<td>5%</td>
<td>14%</td>
<td>28%</td>
<td>28%</td>
<td>23%</td>
<td>2%</td>
<td>0%</td>
<td>0%</td>
<td>3,849</td>
</tr>
<tr>
<td>Midwest</td>
<td>6%</td>
<td>20%</td>
<td>24%</td>
<td>20%</td>
<td>10%</td>
<td>14%</td>
<td>6%</td>
<td>1%</td>
<td>11,155</td>
</tr>
<tr>
<td>Southeast</td>
<td>11%</td>
<td>32%</td>
<td>39%</td>
<td>12%</td>
<td>4%</td>
<td>2%</td>
<td>0%</td>
<td>0%</td>
<td>5,107</td>
</tr>
<tr>
<td>Southwest</td>
<td>14%</td>
<td>25%</td>
<td>23%</td>
<td>21%</td>
<td>3%</td>
<td>10%</td>
<td>4%</td>
<td>0%</td>
<td>9,218</td>
</tr>
<tr>
<td>Western</td>
<td>5%</td>
<td>19%</td>
<td>20%</td>
<td>18%</td>
<td>6%</td>
<td>12%</td>
<td>18%</td>
<td>2%</td>
<td>12,809</td>
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<tr>
<td>Total</td>
<td>10%</td>
<td>23%</td>
<td>23%</td>
<td>20%</td>
<td>6%</td>
<td>10%</td>
<td>6%</td>
<td>1%</td>
<td>52,444</td>
</tr>
</tbody>
</table>

5.3.2. All Intrastate Companies

Similarly, the regional pipe size distribution for all intrastate pipe in the United States was compiled from the 2011 PHMSA Transmission Annual Report data and is shown in Table 3. Approximately 40% (approximately 43,700 miles) of the miles shown in this table are miles operated by the 56 AGA members that responded to the survey.

Table 3: Regional Pipe Size Distribution – All US Intrastate Miles

<table>
<thead>
<tr>
<th>Region</th>
<th>&lt;6”</th>
<th>6/8”</th>
<th>10/12/14”</th>
<th>16/18/20”</th>
<th>22/24”</th>
<th>26/30”</th>
<th>34/36”</th>
<th>≥40”</th>
<th>Total Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central</td>
<td>26%</td>
<td>39%</td>
<td>20%</td>
<td>13%</td>
<td>3%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>17,300</td>
</tr>
<tr>
<td>Northeast</td>
<td>2%</td>
<td>18%</td>
<td>34%</td>
<td>27%</td>
<td>15%</td>
<td>4%</td>
<td>0%</td>
<td>0%</td>
<td>3,818</td>
</tr>
<tr>
<td>Midwest</td>
<td>7%</td>
<td>22%</td>
<td>24%</td>
<td>21%</td>
<td>9%</td>
<td>12%</td>
<td>4%</td>
<td>0%</td>
<td>14,375</td>
</tr>
<tr>
<td>Southeast</td>
<td>10%</td>
<td>36%</td>
<td>35%</td>
<td>12%</td>
<td>4%</td>
<td>2%</td>
<td>0%</td>
<td>0%</td>
<td>11,144</td>
</tr>
<tr>
<td>Southwest</td>
<td>8%</td>
<td>20%</td>
<td>22%</td>
<td>24%</td>
<td>10%</td>
<td>8%</td>
<td>6%</td>
<td>2%</td>
<td>47,328</td>
</tr>
<tr>
<td>Western</td>
<td>5%</td>
<td>18%</td>
<td>22%</td>
<td>18%</td>
<td>6%</td>
<td>12%</td>
<td>17%</td>
<td>2%</td>
<td>13,451</td>
</tr>
<tr>
<td>Total</td>
<td>10%</td>
<td>25%</td>
<td>24%</td>
<td>20%</td>
<td>8%</td>
<td>7%</td>
<td>5%</td>
<td>1%</td>
<td>107,416</td>
</tr>
</tbody>
</table>

The ratio of intrastate miles for the 56 AGA responding companies to total intrastate miles in each region is shown in Figure 13. The graph shows that there are a large number of miles in the Southwest region (Texas, Louisiana, Oklahoma, etc.) from companies that did not respond to the AGA survey or are not members of AGA. A large portion of these miles are likely associated with midstream companies in gas production areas.

A review of the data for interstate companies shows a shift to predominantly larger diameter pipeline, as well as a larger percentage of mileage in Class 1 and 2 locations when compared to the intrastate companies. Because of these different
characteristics, traditional interstate pipelines operate at higher pressures and rely more heavily on ILI.

Figure 13: Comparison of AGA Respondent and US Intrastate Total Intrastate Population

5.4. MAOP Testing Cost Estimates

For the public, utility commissioners, and pipeline operators, the analysis of economic factors is important in the decision of whether to pressure test, lower the operating pressure, or replace the pipeline. These decisions are influenced strongly by the specific gas supply market, customer base characteristics and delivery contracts, as well as other project constraints. Regional environmental and political considerations will also factor into the decision process.

In order to help quantify the potential impact of increased testing requirements to intrastate operators, cost estimate ranges for typical hydrostatic testing of in-service transmission pipelines and main replacement projects were developed. The cost estimates were created using EN Engineering internal project experience as well as project cost data collected during discussions with select AGA Member companies. These companies had varying levels of experience with hydrostatic testing of in-service pipe (extremely limited to several hundred miles) and the data provided was a collection of engineering cost estimates and project experience. Additionally, these companies included one with a large percentage of its system in rural areas as well as companies with experience performing tests in urban (Class 3, 4 and HCA) locations with considerable environmental constraints. All companies interviewed had experience with pipeline replacement / installation and data provided was from recent project experience or engineering estimates.

5.4.1. Cost Estimate - Background

EN Engineering project experience and the AGA member company input identifies class location as a primary variable in the cost of a project. Construction in an urban environment typically includes: increased permitting requirements, restrictions on working hours and equipment, a large amount of work in or crossing road right-of-ways, higher material costs, an increased contractor work force (traffic control, etc.), and longer project duration. Urban areas also have limited right-of-way availability with higher acquisition costs.
Economies of scale are also a main driver of project cost, especially for hydrostatic testing projects that have a high percentage of fixed costs. A hydrostatic test project with test segment lengths of less than 0.75 miles can have a per mile cost more than five (5) times that of a project with test segment lengths greater than 2.0 miles. Typically, due to construction and system design constraints, urban areas will have shorter test segments than rural areas, further increasing the price variation between Class 1 and 2 non-HCA locations and Class 3, 4 and HCA areas.

As discussed in section 3.5, approximately 18.5% of pipe that has been pressure tested to less than 1.25 times MAOP or has no documented pressure test is in a Class 3, 4 or HCA location. The remaining 81.5% of pipe is located in a Class 1 or 2 non-HCA location. In order to take into consideration class location and the various challenges, and presumably higher costs associated with MAOP testing and replacement in an urban environment, weighted averages based on cost estimate ranges were developed\(^7\). These weighed averages assume pipe in a Class 1 or 2 non-HCA location has a minimum cost and that pipe in Class 3, 4 or HCA locations has a maximum cost.

The cost estimate ranges developed in this study intend to account for typical variation of the factors that affect the scope of a hydrostatic test or pipe replacement project.

5.4.2. Cost Estimate – Hydrostatic Test

Current industry experience with in-service hydrostatic testing is limited. As a result, best effort cost ranges were developed utilizing available data and engineering judgment. The minimum and maximum cost range estimates for a typical hydrostatic test project based on the central region (cost factor of 1.0) are shown Table 4. These cost estimates exclude consideration of atypical events such as testing failures.

In this study hydrostatic testing cost estimates and calculations are regionalized using the labor factor shown in Figure 12. Since labor costs account for a high percentage of the overall cost of a hydrostatic test project, the labor factor is utilized in these estimates rather than the overall construction factor.

---

\(^7\) Weighted Average = Min * (% of Pipe Class 1,2 Non HCA)+Max*(% Class 3, 4, HCA)
Table 4: Hydrostatic Testing Project Cost Estimates of In-Service Pipe for Central Region

<table>
<thead>
<tr>
<th>Nominal Pipe Size</th>
<th>Minimum Estimate ($/Mile)</th>
<th>Maximum Estimate ($/Mile)</th>
<th>Weighted Average ($/Mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 6”</td>
<td>108,000</td>
<td>1,287,500</td>
<td>326,400</td>
</tr>
<tr>
<td>6/8”</td>
<td>111,600</td>
<td>1,718,800</td>
<td>409,200</td>
</tr>
<tr>
<td>10/12/14”</td>
<td>117,000</td>
<td>1,718,800</td>
<td>413,600</td>
</tr>
<tr>
<td>16/20”</td>
<td>185,400</td>
<td>1,822,900</td>
<td>488,600</td>
</tr>
<tr>
<td>22/24”</td>
<td>283,500</td>
<td>2,369,800</td>
<td>669,900</td>
</tr>
<tr>
<td>26/30”</td>
<td>314,100</td>
<td>2,790,800</td>
<td>772,700</td>
</tr>
<tr>
<td>34/36/38”</td>
<td>353,300</td>
<td>3,139,700</td>
<td>869,300</td>
</tr>
<tr>
<td>≥40”</td>
<td>397,500</td>
<td>3,284,100</td>
<td>932,100</td>
</tr>
</tbody>
</table>

5.4.3. Cost Estimate – Replacement

Similar to hydrostatic testing projects, the cost range estimates for a typical pipe replacement project based on the central region (cost factor of 1.0) are shown in Table 5. In this study, pipe replacement estimates and calculations are regionalized using the total factor shown in Figure 12. For these cost ranges, the total factor is used since it represents the regional variance of a pipe installation project.

Table 5: Pipe Replacement Project Cost Estimates for Central Region

<table>
<thead>
<tr>
<th>Nominal Pipe Size</th>
<th>Minimum Estimate ($/Mile)</th>
<th>Maximum Estimate ($/Mile)</th>
<th>Weighted Average ($/Mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 6”</td>
<td>247,500</td>
<td>1,562,500</td>
<td>491,000</td>
</tr>
<tr>
<td>6/8”</td>
<td>1,041,000</td>
<td>1,953,100</td>
<td>1,209,900</td>
</tr>
<tr>
<td>10/12/14”</td>
<td>1,240,200</td>
<td>2,392,700</td>
<td>1,453,600</td>
</tr>
<tr>
<td>16/20”</td>
<td>2,044,200</td>
<td>2,392,700</td>
<td>2,108,700</td>
</tr>
<tr>
<td>22/24”</td>
<td>2,409,700</td>
<td>4,320,400</td>
<td>2,763,600</td>
</tr>
<tr>
<td>26/30”</td>
<td>2,860,100</td>
<td>4,894,600</td>
<td>3,236,900</td>
</tr>
<tr>
<td>34/36/38”</td>
<td>3,583,600</td>
<td>5,468,800</td>
<td>3,932,700</td>
</tr>
<tr>
<td>≥40”</td>
<td>4,208,600</td>
<td>7,031,300</td>
<td>4,731,400</td>
</tr>
</tbody>
</table>

These cost estimates reflect recent project experience and engineering cost estimate information and were developed using the current demand in the industry. A significant shift in construction demand may cause costs to increase. Additionally, these estimates do not reflect the costs associated with pipe replacement in an extreme situation / densely populated city center. In an extreme situation / densely
populated city center, a 24-inch OD pressure test could cost more than $15 million per mile and a 36-inch OD pipe replacement could cost more than $50 million per mile.

5.5. **Cost comparison**

At first glance, comparison of testing in-service pipelines versus replacement indicates that testing is the least cost option, particularly for large diameter lines where replacement costs can exceed four (4) times that of testing costs. However, difficult testing scenarios and other considerations can tilt the economics and make other options such as replacement the more prudent option. Costs and considerations companies may include in a hydrostatic test versus replace decision include:

- Condition of current pipe and coating – pipe in poor condition is more susceptible to hydrostatic test failures.
- Pipeline maintenance costs – replacement can reduce annual maintenance costs
- Capacity considerations – replacement allows for system capacity increases.
- Accounting – state accounting and project compensation allowances may influence repair versus replace considerations.

For additional discussion on potential barriers, refer to section 6.

**Figure 14** represents a comparison between testing and replacement costs. These numbers are based on the Central Region, which has a cost factor of 1.0. Costs for other regions can be calculated by multiplying the central region costs by the factors listed within **Figure 12**.

![Figure 14: Cost Comparison - Hydrostatic Test versus Replacement Costs for Central Region](image-url)
5.6. Potential Costs – 56 AGA Member Reporting Companies

Minimum-maximum plots were developed to help illustrate the potential cost impact to the 56 AGA member companies that responded to the survey if regulations are changed to require testing on previously untested pipe or to a minimum test factor of 1.25.

From Figure 4, based on 54 AGA member responses, the characterization of pressure testing was as follows:

- 34% tested to less than 1.25 times MAOP or no documented pressure test (17,048 miles).
- 27% tested to less than 1.1 times MAOP or no documented pressure test (13,545 miles).

In order to develop cost estimates representative of all 56 companies providing input into the study, the same ratios from Figure 4 were applied to the remaining two (2) companies. Using these ratios, mileage subject to each pressure test category for the 56 AGA member companies was calculated to be:

- 17,778 miles tested to less than 1.25 times MAOP or no documented pressure test.
- 14,160 miles tested to less than 1.1 times MAOP or no documented pressure test.

Additionally, the minimum-maximum plots assume:

- The pipe size and regional distribution presented in Table 2.
- Regional construction factors presented in Figure 12.
- The ratios for pressure test groupings, class/HCA groupings, and ability to remove pipe from service are uniform for all regions, class locations and pipe sizes.


The figure below shows regional potential testing costs for the 56 AGA reporting companies to pressure test 17,778 miles of pipe that has not been tested to at least 1.25 times MAOP or has no documented pressure test. The large cost ranges on the graph are indicative of the large amount of uncertainty and the wide range in project scope for a hydrostatic testing project.
5.6.2. Minimum-Maximum Cost Estimates - Replacement

The following figure illustrates the regional potential costs to the 56 AGA reporting member companies to replace the same amount of pipe. Although the costs for replacement are higher than for testing, there is a greater predictability of cost for replacement projects as compared to testing projects.

5.6.3. Cost Scenarios – 56 AGA Respondent Companies

At the present time, the content of future rulemaking is unknown. As a result, four (4) cost scenarios were reviewed in order to help quantify the economic impact of various changes in regulation could have. Projected costs were developed for the following scenarios:

- Scenario 1 – MAOP testing on all pipe, all class locations, not pressure tested to at least 1.25 times MAOP or having no documented pressure test.
- Scenario 2 - MAOP testing on all pipe, all class locations, not pressure tested to at least 1.1 times MAOP or having no documented pressure test.
- Scenario 3 - MAOP testing on all pipe in Class 3, 4 and HCA locations, not pressure tested to at least 1.25 times MAOP or having no documented pressure test.
- Scenario 4 - MAOP testing on all pipe in Class 3, 4 and HCA locations, not pressure tested to at least 1.1 times MAOP or having no documented pressure test.

5.6.4. Cost Scenario 1

Scenario 1 considers costs for MAOP testing for the 56 AGA member companies with a pressure test less than 1.25 times MAOP or no documented pressure test (all class locations). Using the weighted average cost data presented in Table 4 and Table 5, regional and national costs were developed to perform MAOP testing on pipe in all class locations that have not been pressure tested to at least 1.25 times MAOP or that have no documented pressure test.

The cost projection assumes:
- 31% of pipe that has not been pressure tested to at least 1.25 times MAOP or has no documented pressure test cannot be removed from service and is replaced.
- The remaining 69% of pipe that can be removed from service is hydrotested.

The cost projections, shown in Figure 17, indicate that it will cost the 56 AGA reporting companies $24.71 billion to hydrotest and / or replace the projected 17,778 miles of pipe in their systems that have not been pressure tested to at least 1.25 times MAOP or have no documented pressure test.

Projected MAOP Confirmation Costs

![Projected MAOP Confirmation Costs](image)

Figure 17: AGA Companies; all Class Locations; PT<1.25*MAOP; 31% Replacement

5.6.5. Cost Scenario 2

Scenario 2 considers costs associated with MAOP confirmation for 56 AGA member companies with a pressure test less than 1.1 times MAOP or no documented pressure test (all class locations). This scenario requires a new “weighted average”
since, as discussed in Section 3.5, a higher proportion, 21.6%, in this pressure test range is in a Class 3, 4 and HCA location. The weighted averages used for the cost projections in this scenario, normalized to the central region (cost factor 1.0) are shown in Table 6.

The cost projection assumes:

- 42% of pipe that has been pressure test to less than 1.1 times MAOP or has no documented pressure test cannot be removed from service and is replaced.
- The remaining 58% of pipe that can be removed from service is hydrotested.
Table 6: Weighted Average Values for MAOP Confirmation Costs - Scenario 2

<table>
<thead>
<tr>
<th>Nominal Pipe Size</th>
<th>Hydrostatic Test Weighted Average ($/Mile)</th>
<th>Pipe Replacement Weighted Average ($/Mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 6&quot;</td>
<td>363,100</td>
<td>531,900</td>
</tr>
<tr>
<td>6/8&quot;</td>
<td>459,200</td>
<td>1,238,400</td>
</tr>
<tr>
<td>10/12/14&quot;</td>
<td>463,500</td>
<td>1,489,500</td>
</tr>
<tr>
<td>16/20&quot;</td>
<td>539,600</td>
<td>2,119,600</td>
</tr>
<tr>
<td>22/24&quot;</td>
<td>734,800</td>
<td>2,823,100</td>
</tr>
<tr>
<td>26/30&quot;</td>
<td>849,800</td>
<td>3,300,200</td>
</tr>
<tr>
<td>34/36/38&quot;</td>
<td>956,100</td>
<td>3,991,400</td>
</tr>
<tr>
<td>≥40&quot;</td>
<td>1,021,900</td>
<td>4,819,200</td>
</tr>
</tbody>
</table>

The cost projections, shown in Figure 18 estimate that it will cost the 56 AGA reporting companies $23.27 billion to hydrotest and/or replace the projected 14,160 miles of pipe in their system that have not been pressure tested to 1.1 times MAOP or that have no documented pressure test.

Projected MAOP Confirmation Costs

![Projected MAOP Confirmation Costs Chart]

Figure 18: AGA Companies: all Class Locations; PT<1.1*MAOP; 42% Replacement

5.6.6. Cost Scenario 3

Scenario 3 considers costs associated with MAOP confirmation for 56 AGA reporting companies with segments that have been pressure tested to less than 1.25 times MAOP or have no documented pressure test (Class 3, Class 4 and HCA only). For cost estimates in this scenario, the maximum estimated cost from Table 4 for pressure test and Table 5 for replacement is used since 100% of the pipe is in a Class 3, 4 or HCA location.

The cost projection assumes:
- 31% of pipe that has been pressure tested to less than 1.25 times MAOP or has no documented pressure test cannot be removed from service and is replaced.

- The remaining 69% of pipe that can be removed from service is hydrotested.

The cost projections, shown in Figure 19, estimate that it will cost the 56 AGA reporting companies $11.90 billion to hydrotest and/or replace the projected 3,289 miles of Class 3, 4 and HCA pipe in their systems that have not been pressure tested to at least 1.25 times MAOP or have no documented pressure test.

**Projected MAOP Confirmation Costs**

![Projected MAOP Confirmation Costs](image)

**Figure 19:** AGA Companies; Class 3, 4 and HCA; PT<1.25*MAOP; 31% Replacement

### 5.6.7. Cost Scenario 4

Scenario 4 considers costs to the 56 AGA member companies where only pipe in Class 3, 4 or HCA locations that has not been pressure tested to at least 1.1 times MAOP or has no documented pressure test requires MAOP confirmation. For cost estimates in this scenario, the maximum estimated cost from Table 4 for pressure test, and Table 5 for replacement are used since 100% of the pipe is in a Class 3, 4 and HCA location.

The cost projection assumes:

- 42% of pipe that has been pressure tested to less than 1.1 times MAOP or has no documented pressure test cannot be removed from service and is replaced.

- The remaining 58% of pipe that can be removed from service is hydrotested.

The cost projections, shown in Figure 20, indicate that it will cost the 56 AGA reporting companies $11.21 billion to hydrotest and/or replace the projected 3,058 miles of Class 3, 4 and HCA pipe in their system that have not been pressure tested to at least 1.1 times MAOP or have no documented pressure test.
Projected MAOP Confirmation Costs

Figure 20: AGA Companies; Class 3, 4, HCA; PT>1.1*MAOP; 42% Replacement

5.6.8. Evaluation of AGA Cost Projections

A plot showing the distribution of miles and costs for each of the pressure test ranges and class location groupings is shown in Figure 21 below.

Figure 21: Total Projected Cost versus Distribution of Total Miles by PT Range and Class Location

Observations from this plot include:

- 18.5% of pipe with a pressure test less than a 1.25 times MAOP or no documented pressure test is in a Class a 3, 4 or HCA location. This 18.5% of pipe is projected to account for nearly 50% of the overall cost to perform MAOP confirmation on all pipes without a pressure test to at least 1.25 times MAOP or no documented pressure test.
- More than 90% of the projected costs to test or replace pipe that has been pressure tested to less than 1.25 MAOP is allocated to pipe that has been pressure tested less than 1.1 times MAOP or has no documented pressure test.
5.7. Potential Costs – Intrastate Operators

Looking at the entire population of intrastate miles, potential MAOP confirmation costs rise substantially, primarily driven by the large number of miles located in the southwest region of the United States. A minimum-maximum plot that shows the potential cost ranges to hydrostatic test 69% and replace 31% of all intrastate pipe that has not been pressure tested to 1.25 times MAOP or have no documented pressure test is depicted in Figure 22. A second minimum-maximum plot demonstrating the same scenario except only for pipe in Class 3, 4 or HCA locations (18.5% of pipe) is shown in Figure 23.

The plots were created using the assumption that non-AGA intrastate companies have an equivalent proportion of pipe that has not been pressure tested to at least 1.25 times MAOP as the reporting 56 AGA companies. For this section, unless otherwise stated, all assumptions discussed in sections 5.5 and 5.6 apply. Cost estimates shown for intrastate pipelines do not include the approximately 8,800 miles of interstate pipeline operated by the 56 responding AGA member companies.

![Minimum-Maximum Plot](image.png)

*Figure 22: Testing and Replacement Costs; PT<1.25*MAOP; all Class Locations*
Figure 23: Testing and Replacement Costs: PT<1.25xMAOP: Class 3.4 and HCA Locations

An escalation of costs to intrastate pipeline operator’s customers and its other stakeholders will result from the expansion of Congress’ requirements to intrastate transmission infrastructure beyond those covered by PSA 2011, increasing the estimated range of costs to industry from $6.0 to $23.0 billion to an estimated range of $32.6 to $124.4 billion.

5.7.1. Cost Scenario 5

A cost scenario for intrastate pipe was performed to project the cost of applying the assumptions used in cost scenario 1 to all approximately 108,000 intrastate miles in the United States. This cost scenario uses the weighted average cost data presented in Table 4 and Table 5 to project regional and national costs to perform MAOP confirmation on pipe in all class locations that has not been pressure tested to at least 1.25 times MAOP or has no documented pressure test.

The cost projection assumes:

- 31% of pipe that has not been pressure test to at least 1.25 times MAOP or has no documented pressure test cannot be removed from service and is replaced.
- 69% of pipe that can be removed from service is hydrotested.

The projection uses the pipe size and regional distribution presented in Table 3, and the regional construction factors presented in Figure 12. The ratios presented for pressure test ranges, class/HCA groupings, and ability to remove pipe from service are assumed to be uniform for all regions, class locations and pipe sizes.

The cost projections, shown in Figure 24, estimate that it will cost the United States intrastate transmission pipeline operating companies $49.6 billion to hydrotest and/or replace the 36,414 miles of pipe in their system that have not been pressure tested to at least 1.25 times MAOP or have no documented pressure test.
Projected MAOP Confirmation Costs

![Bar chart showing projected confirmation costs by region and method (Replacement vs. Hydrotest).](image)

*Figure 24: US Intrastate; PT < 1.25*MAOP; all Class Locations*

Additional detailed cost projection scenarios are not formally presented in this paper for intrastate pipe. The cost projections were performed using the same ratios as presented previously, thus the cost relation for intrastate pipe scenarios will be similar to that shown for the 56 AGA companies. Scenarios for all US intrastate transmission lines, equivalent to scenarios 2, 3, and 4 performed for the 56 AGA reporting companies, are provided in Table 7.

### 5.8. Summary of Costs

The cost projections for the scenarios discussed in section 5.6 and 5.7 are summarized in Table 7.

These estimated costs assume:

- 31% of pipe that has not been pressure tested to at least 1.25 times MAOP or has no documented pressure test cannot be removed from service and is replaced.
- The remaining 69% that has not been pressure tested to at least 1.25 times MAOP or has no documented pressure test can be removed from service and is hydrotested.
- 42% of pipe that has been pressure tested to less than 1.1 times MAOP or has no documented pressure test cannot be removed from service and is replaced.
- The remaining 58% that has been pressure tested to less than 1.1 times MAOP or has no documented pressure tested can be removed from service and is hydrotested.

All cost figures in this study are in present value and cost projections were performed using current estimated representative hydrotest and pipeline construction costs. A severe escalation in workload may cause costs to rise due to increased demand.
<table>
<thead>
<tr>
<th>Pressure Test Range</th>
<th>Class / HCA</th>
<th>AGA Member Companies</th>
<th>All US Intrastate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Scenario Number</td>
<td>Miles Requiring MAOP Testing</td>
<td>Projected Cost (000,000)</td>
</tr>
<tr>
<td>PT&lt;1.25MAOP</td>
<td>1, 2, 3, 4, HCA</td>
<td>1</td>
<td>17,778</td>
</tr>
<tr>
<td>PT&lt;1.1MAOP</td>
<td>1, 2, 3, 4, HCA</td>
<td>2</td>
<td>14,160</td>
</tr>
<tr>
<td>PT&lt;1.25MAOP</td>
<td>3, 4, HCA</td>
<td>3</td>
<td>3,289</td>
</tr>
<tr>
<td>PT&lt;1.1MAOP</td>
<td>3, 4, HCA</td>
<td>4</td>
<td>3,058</td>
</tr>
</tbody>
</table>

From this table, the following observations can be made:

- For AGA companies, the cost to complete testing under current federal legislation in Class 3, 4 and HCA locations is projected to be approximately $11.9 billion. If regulations are expanded to include pipe in all class locations, this cost could increase to $24.7 billion.

- Extrapolation to all intrastate pipelines increases costs projections from $23.0 billion to $49.6 billion respectively.

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8 Pressure test range includes pipe with no documented pressure test
9 56 AGA member companies
6.0 BARRIERS TO IMPLEMENTING ADDITIONAL TEST REQUIREMENTS

Potential mandates for additional testing to validate MAOP or testing pipe without a post construction hydrotest will have an impact on the industry; however, until official rulemaking is released and testing plans are implemented by operators on a wider scale, the true impact remains to be seen. Based on input from AGA member companies and service providers, some of the perceived barriers to increased testing are discussed in the subparagraphs below.

6.1 Labor Resources

6.1.1 Utility Workforce

Information from the Bureau of Labor Statistics on Utility Employment Data\(^\text{10}\) shows that from 1991 to approximately 2005 the utility labor force steadily declined in number (Figure 25). Even additional regulations that went into effect during the 2000’s, such as integrity management, did not result in a significant increase in personnel levels.

![Figure 25: Utility Employment Data 1991 to 2012](image)

As a result, if there is a significant change in testing requirements, it is likely that work will need to be outsourced because current operator workforce levels will not be able to support current pipeline safety programs as well as additional testing requirements.

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6.1.2. **Contract Resources**

In order to better understand potential barriers contract resources may encounter as a result of increased testing requirements, surveys were sent to contract resources. The primary issues identified included:

- Project management personnel
- Training
- Qualified welders
- Qualified heavy equipment operators
- Office administrative staff
- Qualified general labor
- Heavy equipment
- Safety personnel

Additionally, the topic of the availability of contract resources was explored, with key feedback including:

- Contractors are already busy with existing workload.
- Due to current work in the state of California, some contractors that have been traditionally used for projects are not available or the price per unit has significantly increased.
- Qualified welders and experienced project management personnel and foreman are difficult to attain.
- Some operators currently are seeing higher costs but in general resources are still available; however, the majority of companies have not implemented significant MAOP testing / replacement projects.

6.2. **Permitting**

In the overall life cycle of a testing or replacement project, permitting typically has the longest duration.

6.2.1. **Testing**

Typical permits for a testing project include:

- Water acquisition.
- Water discharge.
- Temporary workspace easements.

Typical agencies that an operator may have to work with in order to obtain permits for testing projects include:

- State Environmental Protection Agency (EPA).
- Local Municipality, County, State regulatory body for use of land.
- Local, County, State department of transportation for work performed in road right-of-ways.
- Railroad company for work performed in railroad right-of-way.
- Federal Bureau of Land Management (BLM) for work performed on federal lands.
- Army Corps of Engineer for work performed in or near navigable waterways.

The type and number of temporary work space easements / permits required is dependent on the extent of the hydrostatic testing project. Temporary workspace permits are required for each location where excavations are planned, as well as locations where the test will be administered. Work space at testing locations will need to allow for the testing crew to set up equipment such as manifolds, pumps, frac tanks and hydrostatic testing trailers.

In addition to acquiring permits for temporary workspace, permits are also required to acquire water for hydrostatic testing. Typically, when available, the most cost effective water supply for hydrostatic testing is from a local river. In order to use water from a river or navigable waterway, a permit from the Army Corps of Engineers is required. In addition to federal permits, a state or other regulatory authority may also require a permit to use water from a local natural water resource. If there is not a river or other suitable natural water source available, water can be purchased from a local municipality. Permitting requirements and water acquisition costs vary by local municipality.

For a hydrostatic testing project, the most permit extensive component typically is water discharge. In order to discharge water onto the ground or to a natural water source, permits are required from the state EPA. If water is to be returned to a navigable waterway or river, a federal permit from the Army Corps of Engineering is also required. State environmental permits typically specify that the water intended for discharge be tested for constituents including, but not limited to, total oil and grease, pH, total chlorine, benzene, and toluene. The acceptance levels for each of the tests are state EPA specific. If the water to be discharged is not within the specified level, typically filtering is required prior to discharge. The filtering operation is an additional project cost.

In some cases, water may be discharged into a local municipality sewer system. This option has a high cost premium; however, there are less environmental restrictions and permits required.

The permitting process for a hydrostatic test project could take as little as thirty (30) to sixty (60) days for a project with minimal scope of work in an area with less restrictive environmental requirements. A project in an area with strenuous environmental requirements or other burdensome restrictions could take greater than six (6) months.
6.2.2. **Replacement**

The permit requirements for pipe replacement projects include all requirements of a hydrostatic testing project with additional land acquisition, land use, and environmental / wetland permitting requirements. The permitting process for a pipeline replacement project could take as little as thirty (30) to sixty (60) days for a short project in an area with low environmental impact, a small number of road crossings, and no waterway crossings. A project in an area with strenuous environmental requirements or other burdensome restrictions could take one (1) or more years. Typical permits that are required on a pipeline replacement project include:

- Right-of-way acquisition.
- Temporary workspace easements.
- Road crossings.
- Railroad crossings.
- Navigable waterway / other water body crossings.
- Wetland delineation / permits.
- Threatened and endangered species preservation permits.
- Hydrostatic test water acquisition.
- Hydrostatic test water discharge.

Typical agencies that an operator may have to work with in order to obtain permits for replacement projects include:

- State and Federal EPA.
- Local Municipality, County, State regulatory body for use of land.
- Local, County, State department of transportation work performed in road right-of-ways.
- Railroad Company for work performed in railroad right-of-way.
- Federal Bureau of Land Management (BLM) for work performed on federal lands.
- Army Corps of Engineer for work performed in or near navigable waterways.

6.3. **Testing Failures**

The occurrence of failures during a testing project can be unpredictable, with the frequency of failures during hydrostatic testing dependent on the integrity of the pipe and the quality of the pipe manufacture. Pressure test failure rates are not homogenous across testing projects and often occur in clusters at locations of subpar coating, aggressive environmental conditions, and/or pipe of common manufacturer production run. The variability in failure occurrence makes it difficult to predict the number of failures that will occur during a
testing project. Testing failures add significant costs to a project and can considerably affect the construction timeline, lengthening the duration that the pipeline section is out of service. To mitigate this risk, some operators may choose to perform ILI runs where feasible prior to commencing a pressure test and initiating repairs in areas of indications as appropriate to alleviate failures during the test.

6.4. Design Considerations

The existing configuration of a pipeline has a substantial effect on the scope, duration, and cost of a hydrostatic testing project for an in-service transmission pipeline. During project planning, a system design review must be performed to identify any component that will require replacement in order to complete a successful hydrostatic test project. All components in the pipeline must have a full diameter opening so that cleaning, fill, dewater, and drying pigs can pass through the system. Some connection openings (i.e. branch, tee, stopple fitting, etc.) may need to be barred to ensure that pigs do not become trapped or lost. Internal connections (i.e. internal drips, etc.) that could impede the passage of a pig should be removed.

Any modifications and repairs that have been made to the pipeline during maintenance should also be reviewed during project planning. At increased testing pressures, certain modifications, such as leak clamps and stopple fittings, may be susceptible to leaks or rupture during testing.

The following pipeline components typically are flagged for replacement or additional review during hydrostatic test planning:

- Reduced port valves (reduced bore ball valves, plug valves, etc.).
- Unbarred tees, branches, or other connection.
- Stopple fittings and other line stop installations.
- Internal connections including internal drips.
- Pipeline repairs (leak clamps, type A sleeve, type B sleeve, etc.).

If the existence and/or location of a restrictive component is unknown, it could result in a difficult to locate leak or an obstructed cleaning/drying pig. This type of event could cause significant project delays, lengthen the amount of time the pipeline is out of service, and increase project costs.

Test section length is also dependent on the design of the pipeline. A pipeline with diameter changes may need to be tested in multiple sections depending on multi-diameter size pig availability and capabilities.

6.5. Outage Management

For pipelines with single source and/or peak customers for whom the operator's system will be unable to supply gas, or an adequate amount of gas, while the section of pipeline to be tested is out of service, the operating company may need to provide a temporary gas supply. The temporary gas supply method employed will vary depending on the number of customers affected, the quantity of gas required, and the expected length of time that a
pipeline is out of service. For a limited number of residential customers, a frequently used method to supply gas is compressed natural gas (CNG) or liquefied natural gas (LNG) bottles. If a large gas supply is required, the use of one or more LNG tankers is typically the most effective solution. In some cases, the logistics and cost of outage management solutions can be a detriment to the testing alternative.

6.6. System Configuration

AGA member operators have a significant percentage of their transmission lines functionally intertwined with their distribution systems. These transmission lines are both geographically and operationally influenced by the locale and operational characteristics of the supplied distribution systems.

Stemming from the distribution system “influence” on their transmission infrastructures, the ability to run pigs for hydrostatic testing of these lines is markedly limited for AGA member operators. As seen in Section 3.7, greater than 60% of the AGA member survey transmission assets, regardless of the class location, are not ILI-able, thus likely would require capital outlay to convert them to allow the passing of a drying/cleaning pig. For the significant percentage of the non-piggable miles, especially in Class 3 or 4 locations, this capital outlay may make replacement of these lines more cost effective than testing to confirm MAOP.

Single source feeds to large volume customers or to distribution load centers is a primary driver toward the escalation of costs of MAOP testing plans for AGA member companies. Given limited ability to provide temporary gas supply to these loads, lines with this characteristic may require the more costly alternative of pipe replacement.

Some transmission networks which feed distribution systems are configured such that pressure sub-systems within the transmission network cannot have pressure lowered in just the immediate area of the MAOP testing work. Isolation of the work area is not possible without affecting supplied area loads which need to be maintained. This situation precludes less expensive testing, requiring replacement with commensurate elevated costs, or engineering and construction of additional distribution supply regulator stations.

Intrastate Class 1 or Class 2 lines supplying transmission networks feeding distribution systems may not be looped nor have multiple take points from interstate lines. These lines may require loop, supply tap, or bypass construction to make testing feasible or may even require pressure deration with parallel line construction.

6.7. Testing and Construction Season

Weather and climate constraints are the primary limitations on the construction season. In addition to weather considerations, hydrostatic test projects require the pipeline to be removed from service and are affected by operational system constraints. Due to load requirements in the winter heating and summer cooling months, pipeline hydrostatic testing construction scheduling has gradually concentrated on the spring and fall season “shoulder months”. The effect climate and operational capacity requirements have on the construction season will vary by operating company. Limits on the construction season may lengthen the implementation duration of operators’ MAOP testing plans, and/or affect costs associated with implementation.
As mentioned earlier in this report, testing and replacement project durations are affected by right-of-way acquisition, test medium procurement (i.e. water), and both construction and environmental permitting bottlenecks. Their impacts will be compounded by the activity window limitations.

Jurisdictional moratoria on construction (i.e. due to new and recently reconstructed pavement) also affect the duration of testing and replacement projects. These impacts are also compounded by the activity window limitations due to weather and operational capacity considerations. The limited time window to perform hydrostatic testing projects may compel an operator to opt for replacement. Ramp-up in construction during shoulder months may result in contractor resource availability constraints further driving cost escalation.

6.8. Drying the Line

Following a successful hydrostatic test, the pipeline is typically dewatered into frac tanks or directly into an adjacent test section. The pipeline is next dried by running polyurethane and foam pigs through the system. A typical standard is to run foam pigs through the pipeline until they are dry within 1/4-inch of the surface. After drying with the foam pigs many companies require compressed air to be run through the pipeline until a -38°F dew point is held for a specified length of time.

In areas with elevation changes, extra effort may be required to ensure that all water is removed from the pipeline since water that pools in low spots increases the internal corrosion risk. Extra effort could include contracting a drying crew that uses nitrogen, methanol, desiccant dryers, etc. to ensure the pipeline is dry.

Work space needs for hydrotest equipment can be sizable, particularly for frac tanks which have large footprints. Elevation changes and the extra effort described for drying the line will result in extended project durations. These space and time factors will shorten the length of line that can be hydrotested at a single process, specifically in congested Class 3 or Class 4 areas, resulting in cost escalation for hydrotests in these locations.

6.9. Additional Barriers

6.9.1. General Public

Ratepayer advocacy groups objecting to the higher cost alternative of pipe replacement could delay or otherwise hamper execution of this alternative. Similarly, public concerns could also detrimentally affect the execution of either testing or replacement construction plans. Right-of-way acquisitions and approvals are influenced by these factors. In some instances, ratepayer advocacy may be proponents for additional (unnecessary) testing. Public relations and community outreach efforts will need to be expended to mitigate these concerns for a subgroup or full constituency of stakeholders.

6.9.2. Site Specific Requirements

Specific requirements at crossings (i.e. river canal, road crossings) beyond permitting typically include additional burdens, such as added depth of installation,
use of the Horizontal Directional Drilling (HDD) installation process, heavier pipe wall thickness, abrasion resistant coatings, and casing pipe requirements. These factors may add to the costs of a replacement project.

For jurisdictional specific cases, requirements to remove abandoned pipe from the rights-of-way may add additional costs to the project.

6.9.3. **Urban Development**

Population related development in the immediate proximity of pipeline rights-of-way may limit the availability of line-of-lay for replacement projects. Inability to reach agreements with other providers who use the ROW to temporarily take their lines out of service will impair this alternative, as well as the inability to take the current gas transmission line out of service to prevent an incident occurrence from accidental line impingement during construction in lines-of-lay in close proximity to these existing facilities. These issues may arise even in Class 1 and 2 locations if landowners refuse to grant additional ROW in areas of facilities congestion.

6.9.4. **Availability of Materials**

If the industry mobilizes a large number of replacement projects in a short time frame, the availability of materials for infrastructure, such as line pipe and valves, may become limited. Some operators may resort to standardization to a single strength and wall thickness per diameter so flexibility is enabled to move from project to project, arguments as to overdesign notwithstanding. Difficulties with obtaining valves due to very long lead time have already been experienced by some operators.
7.0 OTHER OPTIONS AND CONSIDERATIONS

7.1 General Discussion

Economic factors will influence an operator’s choice from amongst the prescribed alternatives for MAOP testing. These alternatives: testing, replacement, and pressure reduction, are equally effective for reestablishing MAOP. However, the economics of logistics, infrastructure materials, design, system configuration, skilled pipeline industry labor market, and shortened construction timeframes will be unique to each operator. Adding to the non-uniform landscape of operator analysis will be ratepayer advocacy, other potential political pressures, and jurisdiction-specific requirements.

For MAOP testing on some pipeline sections, traditional capitalization may prove to be the fiscally prudent path, while for others, absorption of O&M costs may instead provide the best cost path.

From a review of Pipeline Safety Enhancement Plans (PSEP) filed to the California Public Utilities Commission, the three major intrastate transmission line operators were faced with unique factors in their decision processes that resulted in different approaches and action plans to respond to the CPUC mandates. Review also suggests that given the wide variation in system constraints and other factors to which other intrastate and LDC transmission line operators are exposed, differences in strategies and action plans for operators across the country will be necessary.

7.1.1 Aggregate U.S. Operator Implementation

As noted in Section 5.8, a five-fold increase in the number of miles requiring testing results from the inclusion of Class 1 and Class 2 non-HCA lines.

87% of lines included in PSA 2011’s requirements for review of records for MAOP verification have been found to meet TVC records criteria by LDC and intrastate transmission line operators. Thus, under current regulation, 3% of U.S. intrastate lines will require some type of additional MAOP confirmation efforts. With rulemaking changes to require increased testing, the percentage increases eleven-fold to 34%. This results from the significant increase in the number of miles that would become subject to MAOP testing if regulations require testing in all class locations that have not been tested up to 1.25 times MAOP or have no documented pressure test.

7.1.2 Operator Plan Schedules and Impacts on Customers

Strained industry resources may result in extended aggregate implementation of MAOP testing and replacement efforts. This effect may be offset somewhat by service provider ramp-up driven by greater returns from cost escalation, but no data to quantify the predicted effect is available at this time.

Strained industry resources may also delay construction for large volume load additions, potentially constraining commercial/industrial customer productivity.
7.1.3. **Environmental and Other External Constraints**

The actions associated with overcoming the barriers discussed in Sections 6.2 through 6.9 will expand in conjunction with the miles of transmission pipelines to which regulations are imposed.

7.1.4. **Resource Availability**

Price elasticity to labor demand may be at high sensitivity, given the current status of availability of skilled labor for natural gas systems. There are indications that the collective cost is already higher due to the California experience.

7.2. **Potential Subpart O Conflicts**

MAOP testing activities may affect an operator’s implementation of the risk assessment, remedial actions, and the performance measurement aspects of an operator's Transmission Integrity Management (TIMP) plan, as required by 49 CFR Part 192 Subpart O. An operator’s TIMP risk-based prioritization of assessments and remedial actions may be impacted on an ongoing basis as MAOP testing program work continues, with the required periodic assessments and data analysis being complicated by or conflicting with actions and data stemming from MAOP testing or replacement projects.
8.0 CONCLUSIONS

While the specific relationships of scope and costs are difficult to assess, the expansion of regulations in the state of California has resulted in additional costs resulting from increased testing and replacement. Expansion of regulations will have a considerable effect to the industry, with actual costs driven by the specific testing and timeline mandates implemented by PHMSA and state jurisdictional authorities.

Testing is logistically complex and usually requires some redesign and reconfiguration of the system. In some cases, replacement may be a viable alternative to testing, and may be the only alternative for pipes that cannot be removed from service. Lowering pressure is another viable option; however, resulting capacity restrictions may require construction of substantial additional infrastructure.

Timelines for implementing testing and replacement projects are protracted as a result of permitting requirements, which typically are the longest duration component to a project. In addition, seasonal constraints limit the timeframe in which work can be completed.

The projected costs to test or replace pipe in Class 1 and 2 non-HCA locations is substantial, with cost recovery mechanisms being different for testing versus replacement. Given the magnitude of potential cost compared to current capital and operations spending, MAOP testing and replacement programs may need to be spread out over an extended period of time, varying from years to decades depending upon operator-specific economics and pipeline networks.

Potential MAOP testing requirements will result in markedly significant impacts in terms of outage management, resource availability and system configuration. Additionally, skilled resources and aggressive schedules will impact costs as demonstrated by the California experience. A carte blanche application, across all operators, of a standardized method for MAOP testing cannot feasibly be implemented by operators. Operators will need to work individually with each of their state’s regulators to determine the feasible plan for each affected pipeline, and engineering prioritization studies (like those performed by the California companies) may need to be performed individually for each operator in order to facilitate discussions with state regulators and to facilitate implementation of future mandates.
Appendix D

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

Pipeline Safety: Public Workshop
on the Integrity Verification Process
Docket PHMSA-2013-0119

COMMENTS OF THE AMERICAN GAS ASSOCIATION
ON THE
PHMSA DRAFT INTEGRITY VERIFICATION PROCESS

The American Gas Association (AGA), founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 71 million residential, commercial and industrial natural gas customers in the U.S., of which almost 92 percent - more than 65 million customers - receive their gas from AGA members. Today, natural gas meets almost one-fourth of the United States' energy needs.

I. INTRODUCTION

In late June, the Pipeline and Hazardous Material Safety Administration (PHMSA) issued a flow chart reflecting its draft Integrity Verification Process (IVP) for natural gas transmission pipelines. AGA submitted preliminary comments on the draft IVP to help facilitate discussion at the August 7, 2013 PHMSA Workshop. AGA’s preliminary comments highlighted the commitment of AGA’s member companies to pipeline safety and offered amended regulatory language that provides for pressure testing, replacement, in-line inspection (ILI), pressure reduction or abandonment of untested natural gas transmission pipelines operating at greater than 30% specified minimum yield strength (SMYS) in high consequence areas (HCAs). The preliminary comments also included the results of an independent study by EN Engineering, Evaluation of MAOP Testing for Transmission Pipelines. AGA reaffirms its preliminary comments and supplements those comments with this submission.

AGA wants to go beyond the mandate in the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (2011 Pipeline Safety Act) that legislates operators to confirm the established Maximum Allowable Operating Pressure (MAOP) of previously untested natural gas transmission pipelines located in HCAs and operating at a pressure greater than 30% of SMYS.
After completing the above mentioned MAOP verification in HCAs, AGA's members want to extend this confirmation to all transmission lines in class 3 and 4 locations, that operate at or above 30% (SMYS) and do not have a record of a pressure test. The estimated cost for MAOP confirmation for HCAs and all class 3 and 4 locations is $18.7 billion dollars for the nation's intrastate natural gas transmission pipelines.

An effort of this magnitude cannot be accomplished with a one size fits all federal safety regulation. AGA represents gas utilities which span all 50 states representing diverse regions and operating conditions. PHMSA must recognize the significant role that state governing bodies will have in funding these actions. Each utility serves a unique and defined geographic area and their system infrastructures vary widely based on a multitude of factors, including facility condition, past engineering practices and materials. Each operator will need to evaluate the actions in light of system variables, the operator's independent integrity assessment, risk analysis and mitigation strategy and what has been deemed reasonable and prudent by their Commissions. A federal safety regulation must be compatible with the legal obligation every public utility has to furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.

AGA commends PHMSA's continuing commitment to pipeline safety and appreciates the opportunity to comment on the PHMSA draft IVP. We recognize the significant effort expended on creating the IVP and support many of the technical principles in the IVP. AGA believes the recommendations provided in our response will result in significant enhancements in the safety and reliability of the nation's natural gas transmission pipeline infrastructure. AGA and its member companies share PHMSA's interest in promulgating regulations that will enhance safety and satisfy the mandates set forth by Congress in the 2011 Pipeline Safety Act.

It should be noted that many AGA member companies are already pro-actively taking actions to address the highest risk transmission pipelines which have no record of a pressure test. It is also important to note that no record of a pressure test does not mean that the records are insufficient to establish the MAOP. Gas utilities will not operate pipelines without sufficient records to establish the MAOP.

In summary:

- **AGA's Commitment to MAOP Pressure Confirmation:** AGA provided PHMSA, in its preliminary comments, with the most comprehensive study that exists regarding the pressure testing or replacement of in-service natural gas transmission pipelines, the *Evaluation of MAOP Testing for In-Service Transmission Pipelines* by EN Engineering. The pressure testing and replacement programs analyzed in this study are already being implemented by some operators. The AGA engineering study will inform PHMSA and
other regulatory agencies regarding the costs projected to be committed by intrastate natural gas transmission pipeline operators to implement the Congressional mandate in Sec. 23(d) of the 2011 Pipeline Safety Act. The Office of the Secretary of Transportation and members of Congress should be made aware of the study so that there is a clear understanding of the magnitude of the proposed effort. AGA supports a risk based approach for the timing of these pressure tests which takes into account service disruptions, the availability of engineering and construction resources, the impact on customers, and other regulatory initiatives that PHMSA may propose.

- **AGA Suggestion for MAOP Testing Regulations**: AGA has submitted herein suggested amended regulatory language to 49 CFR §192.619 *Maximum allowable operating pressure: Steel or plastic pipelines* that provides options that will enhance the safety for those transmission lines located in HCAs with a MAOP that produces a hoop stress of greater than 30% of SMYS and that have not been previously tested. The options presented include pressure testing, ILI inspection, MAOP reduction by 20%, and replacement of the pipeline. The proposed amendment leverages industry practices, PHMSA regulations and proven methodologies for validating the MAOPs of natural gas transmission pipelines. The language is written to follow the legislative mandates in the 2011 Pipeline Safety Act. AGA requests that PHMSA consider the language.

- **Separating the Rulemakings**: PHMSA announced at the Technical Advisory Committee meeting on August 8, 2013 that the IVP reflects PHMSA’s intent to merge many different mandates from the 2011 Pipeline Safety Act and recommendations from the National Transportation Safety Board (NTSB), including expansion of the natural gas Transmission Integrity Management Program, removal of the “Grandfather clause” (defined by PHMSA as 192.619.c). Industry representatives at the workshop expressed that removal of the “Grandfather clause” and MAOP verification should be separated from the expansion of gas transmission integrity management. The two processes have completely separate objectives and their integration into a single process creates unnecessary confusion and complexity. AGA views the removal of the “Grandfather clause” and MAOP verification as a one-time effort which confirms the MAOP of the pipeline with appropriate factors of safety. Integrity management is an ongoing iterative process to ensure the continued long-term integrity of the pipeline.

- **AGA Seeks Clarification on the Expansion of Integrity Management**: AGA supports extending integrity management principles outside of HCAs using a risk based approach. Expanding integrity management principles beyond existing Subpart O requirements incorporates issues such as the concept of a moderate consequence area (MCA), pipe material analysis, remote or automated valves, the potential application of a
spike test for those pipelines which have the threat of cyclic fatigue or stress corrosion cracking, and other elements. Extending integrity management principles outside of HCAs is far more complex than removal of the “Grandfather clause” and MAOP verification requirements. Section 5 of the 2011 Pipeline Safety Act requires PHMSA to evaluate whether integrity management system requirements, or elements thereof, should be expanded beyond HCAs, and to submit a report to Congress on its analysis and findings. Congress also barred promulgation of a final rule until Congress had time to consider the results of the report. AGA is concerned that there are likely to be unintended adverse safety consequences caused by attempting to simultaneously implement regulations for MAOP verification of natural gas transmission pipelines and expanding the integrity assessments of those same transmission pipelines. Within these comments AGA provides general thoughts on integrity management expansion, but its primary recommendation is that PHMSA convene a multi-stakeholder group to determine how to best address these complex technical integrity management issues. AGA will meet with a group of its members in October to discuss the implications of expanding integrity management. AGA welcomes PHMSA’s presence at that meeting.

II. Detailed Comments

A. Separation of MAOP Verification and Gas Transmission IMP Expansion

AGA and the vast majority of speakers and public commenters at the IVP workshop and DOT Technical Advisory Committee meeting stated it is necessary to separate MAOP verification from the elements pertaining to the expansion of natural gas transmission integrity management. In general, MAOP verification is a one-time process to establish the highest pressure that a pipe will be operated at under normal operating conditions. Conversely, the integrity management elements encompass an ongoing iterative process to ensure the continued long-term integrity of the pipeline.

A Subpart J pressure test addresses manufacturing and construction defects and serves a different purpose than integrity management stress testing. The NTSB placed these in separate recommendations because basic engineering principles require them to be handled separately. PHMSA stated at the workshop that it sees all of these things as interrelated and AGA agrees that some of the issues are interconnected. However, just as the current code, 49 CFR 192, separates issues that are linked, the regulations must also make this distinction and be separated. AGA understands the difficulty of moving multiple regulations through the rulemaking process. AGA has offered an effective, non-controversial amendment to 49 CFR §192.619 that would eliminate the grandfather
clause for untested transmission pipelines in HCAs operating at greater than 30% of SMYS and provides several possible methodologies for remediation.

B. MAOP Testing Study

AGA retained EN Engineering to perform an independent study with the objective of providing an analysis of the impacts increased testing requirements may have on AGA member companies, as well as the entire intrastate natural gas transmission pipeline industry. AGA submitted the Evaluation of MAOP Testing for In-service Transmission Pipelines by EN Engineering with our preliminary comments and we are including a slightly revised version with these follow-up comments. The revised engineering study includes updated statistics from the fifty-six (56) AGA member companies that provided information for the original report and reflects the information these companies submitted in their 2012 Natural Gas Transmission Annual Reports. The study evaluates MAOP verification options of pressure testing, replacement and lowering operating pressure. Review of nominal pipe diameters and class location of the data set show a strong correlation between AGA companies that submitted the data and all pipelines classified as intrastate transmission pipelines. Interstate gas transmission pipeline companies have different operating and size characteristics and were excluded from any analysis in this study.

The study concludes that,

- For AGA member companies, the estimated cost to complete MAOP testing in Class 3, 4 and HCA locations is $12.5 billion. If regulations mandate testing in all class locations, this cost increases to $27.1 billion.

- Extrapolation to all intrastate pipelines increases estimated costs to $18.7 billion for testing in Class 3, 4 and HCA locations, and $50.8 billion for all class locations.

- Potential MAOP testing requirements will result in markedly significant impacts in terms of outage management, resource availability and system configuration.

In order to evaluate the potential impacts to the industry, fifty-six (56) AGA member companies (51,488 transmission miles) provided advance data on their anticipated reporting for the calendar year 2012 PHMSA Transmission Annual Report. This report included information pertaining to:

Part K: Miles of Transmission Pipe by Specified Minimum Yield Strength.

Part Q: Gas Transmission Miles by §192.619 MAOP Determination Method.
Part R: Gas Transmission Miles by Pressure Test Range and Internal Inspection.

AGA members submitted the data in February 2013, and this data closely correlates to the data these companies submitted to PHMSA in June 2013. AGA requested that EN Engineering revise the study with the actual data that was submitted in the Annual Report that was published by PHMSA. AGA has attached the revised report as Exhibit 1 AGA also provides Exhibit 2 – AGA Position Paper, Pressure Testing of In-Service Transmission Pipe.

Given the complexity of intrastate natural gas transmission pipeline systems, the fact that many are the single source of supply to a city, community or business, many are directly integrated with distribution systems, and the magnitude of potential costs compared to current capital and operational expenditures, MAOP testing and replacement programs should have direct input from state pipeline safety officials and commissions. MAOP verification should be done using a risk-based approach that takes into account the above factors. Testing of in-service pipelines is logistically very complex and frequently requires some redesign and reconfiguration of the pipeline system.

In some cases, replacement may be a viable alternative to pressure testing, and may be the only alternative for pipes that cannot be removed from service. MAOP reduction is another viable option; however, resulting capacity restrictions may require construction of substantial additional infrastructure.

The removal of the “Grandfather clause” and the creation of new MAOP verification requirements will result in markedly significant impacts in terms of customer outage management, resource availability and system configuration if it does not take into account the specifics of each unique pipeline. Additionally, the limited availability of skilled resources and aggressive schedules will impact costs as demonstrated by the actions being taken by natural gas transmission operators in California. Operators will need to work individually with their state’s regulators to determine a feasible plan for each affected pipeline, and engineering prioritization studies may need to be performed individually for each operator in order to facilitate discussions with state regulators and to facilitate implementation of future mandates.

During the EN Engineering study, several companies were interviewed about the impact of hydrostatically testing or replacing transmission pipelines operating above 30% SMYS that do not have a record of a post-construction pressure test. The companies interviewed provided details on the many challenges and barriers to completion that they are willing to overcome in order to test their untested pipelines. Those barriers include
the limited availability of skilled workforce, limited contractor resources, prolonged permitting timeframes, customer outage management and incompatibility of the existing pipeline configuration.

Given the significant investment already committed by operators and the other issues presented above. AGA supports a risk based approach for the timing of these pressure tests which takes into account service disruptions, the availability of engineering and construction resources, the impact on customers, and other regulatory initiatives that PHMSA may propose.

C. AGA Amended Language to 192.619

Under existing code, §192.619, there are four primary criteria used by pipeline operators in establishing MAOP of a natural gas transmission pipeline: Design Pressure, Pressure Test, Historic Operating Pressure and the Maximum Safe Pressure. The amended language that AGA proposes builds upon the existing system and requires operators to comply with the additional testing requirements mandated in the 2011 Pipeline Safety Act section 23(d). The language allows the existing regulations for distribution pipelines, which are also regulated by 49 CFR §192.619, to remain unchanged. AGA provides the proposed language in this section of the comments and attached Exhibit 3 – AGA Position Paper, Understanding the MAOP Record Verification Process.

The proposed 49 CFR §192.619(e) places very severe operating restrictions on untested natural gas transmission pipelines. All pipelines that operate above 30% SMYS in HCAs will be subjected to one of the following i) a Part 192, Subpart J pressure test, ii) a comprehensive ILI inspection, or iii) a 20% reduction in the MAOP that would be equivalent to a long-term pressure test at 1.25 times the new MAOP. The proposed language follows Congress’s legislative mandate in the 2011 Pipeline Safety Act and eliminates the relief from pressure testing that was provided to some transmission pipelines under both 192.619(a)3 and 192.619(c).

No entity knows the impact that the suggested amendments will have on individual segments of the nation’s infrastructure or the cumulative restrictions on the delivery of natural gas to various regions of the United States. Each operator will have to perform their own engineering study to determine if pipeline segments should be pressure tested, modified to accommodate in-line inspection, operated at a reduced MAOP, replaced or abandoned. The AGA amendment suggests that the studies be completed within 18 months of a final rule. If PHMSA is in agreement with this process, operators could begin the engineering work immediately.
The proposed amended regulation 49 CFR 192.619(e) places the regulatory agency having jurisdiction over the pipeline directly in the evaluation process. An operator's implementation plan should be risk-based, taking into account a variety of factors including an evaluation of the cost, environmental impact, safety, reliability, potential service disruption, and other risk factors. This type of implementation plan cannot be accomplished by a one-size-fits-all federal process. PHMSA's enabling statute establishes federal oversight of state pipeline safety programs. Therefore, PHMSA maintains the ability to delegate oversight for the plans submitted to state regulatory agencies. PHMSA and other agencies have used this method for regulatory oversight. Liquid pipeline operators are already required to submit individualized oil spill response plans for state and federal review under 49 CFR 194.101. Distribution operators are required to submit individualized Distribution Integrity Management Programs per 49 CFR 192 Subpart P. The uniformity of interstate natural gas transmission pipelines makes it logical to have one-size fits all federal rules. The type of regulation does not and will not work for gas utilities operating transmission pipelines.

Below is AGA's proposed regulatory language with new language underlined.

**AGA Proposed Regulatory Language: 192.619**

§192.619 What is the maximum allowable operating pressure for steel or plastic pipelines?
(a) Except as provided in paragraph (c) of this section, no person may operate a segment of steel or plastic pipeline at a pressure that exceeds the lowest of the following:
   (1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:
      (i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, see § 192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or
      (ii) If the pipe is 12¼ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa) gage.
   (2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:
      (i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.
      (ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:
<table>
<thead>
<tr>
<th>Class location</th>
<th>Installed before Nov. 12, 1970</th>
<th>Installed after Nov. 11, 1970</th>
<th>Covered under §192.14</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.1</td>
<td>1.1</td>
<td>1.25</td>
</tr>
<tr>
<td>2</td>
<td>1.25</td>
<td>1.25</td>
<td>1.25</td>
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<tr>
<td>3</td>
<td>1.4</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td>4</td>
<td>1.4</td>
<td>1.5</td>
<td>1.5</td>
</tr>
</tbody>
</table>

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

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

<table>
<thead>
<tr>
<th>Pipeline segment</th>
<th>Pressure date</th>
<th>Test date</th>
</tr>
</thead>
<tbody>
<tr>
<td>—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006. —Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.</td>
<td>March 15, 2006, or date line becomes subject to this part, whichever is later.</td>
<td>5 years preceding applicable date in second column.</td>
</tr>
</tbody>
</table>

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

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

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

(e) Transmission pipelines operating greater than 30% SMYS in HCAs:

(1) For transmission pipelines located in HCAs with a MAOP that produces a hoop stress of greater than 30% of SMYS and that have not been previously tested, the pipeline must be subjected to one of the following tests:

(i) a pressure test consistent with the requirements of section a(2),

(ii) an in-line inspection, (Detail on tools required)

(iii) a reduction in pipeline MAOP by 20%, or

(iv) a procedure that has been approved by the Administrator.

(2) the operator shall within 18 months of this final rule, submit a plan (not to exceed xxx years in duration) to the authorities having safety jurisdiction to test the segment according to one of the methods in (e)(1) above. Post construction pressure tests will be conducted in accordance with Part 192, Subpart J.

Note: The language maintains the existing grandfathering for all distribution pipe and transmission pipe below 30% SMYS. It gives four options for pipe above 30% to comply with MAOP existing pressure tests, new subpart J pressure tests, in-line inspection that confirms the design MAOP.

No deadline has been established for completing the tests because more information is needed from individual operator engineering analysis and the timing requires input from state regulatory agencies and the Federal Energy Regulatory Commission (FERC).

AGA's suggested regulation does not address pipelines that have been pressure tested below 1.25 times the MAOP. Pipe that has undergone pressure tests below 1.25 times the MAOP present less risk than untested pipe, and should therefore not be included in the first phase of the process unless the operator has specific information that warrants inclusion of the pipeline segment. Additionally, consideration must be provided for pipe that has been tested with inert gas. Inert gas tests are a valuable tool in Subpart J testing methodologies. Some operators use inert gas because certain unique features in a pipeline system prevent water from effectively being removed. Examples include fabricated assemblies such as gate
stations or bridle assemblies. Hydrotesting in these cases creates a greater hazard to the public than no testing or inert gas testing under controlled conditions.

D. Implementation Timetable

AGA believes that, for intrastate natural gas transmission pipelines, state specific plans with operator specific timetables are required to address the complexity of testing thousands of miles of in-service transmission pipelines operating above 30% SMYS in HCAs. AGA members support a method similar to that used by Congress in the original Gas Transmission Integrity Management Program. Operators would complete a risk evaluation to select which pipelines present the highest risks and work is performed based upon an analysis of the entire system. Implementation plans pertaining to intrastate transmission pipelines would be submitted to state commissions.

PHMSA stated during the August 8, 2013 Technical Advisory Committee meetings that it believes that the 2011 Pipeline Safety Act required the agency to consult with FERC and state commissions only on the timing for implementation. AGA believes that Congress intended a much broader discussion and AGA supports a broader discussion with FERC and state commissioners on this complex issue. Congress understands that pipelines operate 24 hours a day, 365 days a year. Disruption of this vital energy supply can have national or local implications. FERC and state commissions can provide input on how PHMSA can move forward with the removal of the “Grandfather clause” and the addition of new MACP testing requirements in a way that will not negatively impact supply.

Given the uniqueness of the intrastate transmission pipeline network, it is not possible to fill in the “To Be Decided” boxes in the “Proposed Deadline for Completing Integrity Verification” without a risk based analysis and input from state commissions. HCAs, class location, stress levels, pipe material, type of construction, environment, and date of installation of the pipe may be valid measures and there may be others. Some operators prioritize using the potential impact radius, varying degrees of pipeline attributes such as design and pressure test data, operating and corrosion history. The most important factor may sometimes be system criticality that is unique to each operator.

Operators will give priority to HCAs and higher stress pipe. However, actual testing will be decided by valve locations and therefore, AGA expects there will be much “over-testing” of pipe in non-HCAs. Since testing will be driven by valve locations and customer delivery points, the concept of moderate consequence areas has little meaning to transmission pipelines operating in urban areas. The concept does have application to interstate pipelines in rural areas.
The EN Engineering report estimates that 56% of AGA member pipeline mileage in class 3 and 4 areas is in HCAs (5,549 miles are non-HCAs and 6,964 miles are HCAs). The percentage will vary greatly between operators. Only operators know what portion of this 56% includes pipe that has not been pressure tested. AGA's rough estimate is that it would take 10 years to complete the MAOP verification in HCAs. Again, over-testing will result in more than 56% of the pipe being tested during that period. The timing for completion of all testing in class 3 and 4 depends on how much over-testing is performed during the first phase testing in HCAs.

E. Industry Plans to Advance In-Line Inspection (ILI)

Several research groups are working to expedite the process of establishing the necessary criteria for using ILI as an alternative to pressure testing. The results of these research efforts will allow additional confidence in the ability of ILI not only to establish the strength of the pipeline at the time of construction but also throughout the lifetime of the pipeline. There has been great progress in ILI inspection over the last decade. Establishing the criteria to make ILI an acceptable alternative to pressure testing requires packaging existing technology, field testing and obtaining peer review consensus. Industry supports and encourages PHMSA's continued involvement with these efforts and requests that PHMSA consider expanding its current role in research and development.

An example of research underway is GTI's Hydrotest Alternative Program. GTI states in the summary of the program:

The first step in this process is to define the critical defects that would fail a post-construction hydrotest. The type, size, and shape of the defects would be included in the validation analysis will be limited to time-independent defects that would have been present during a post-construction hydrotest.

While this work may not be completed prior to a Notice of Proposed Rule Making, industry and researchers both are confident that the technology will be commercially available within three years.

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1 Page 13, EN
F. Spike Testing is a Specific Integrity Management Tool

AGA member companies are committed to extensive pressure testing of untested natural gas transmission pipelines. The pressure test requirements as currently defined in Subpart J are appropriate for post-construction pressure testing of newly constructed pipelines and testing in-service transmission pipe. However, much more care must be taken with in-service vintage pipe that was subjected to lower mill test. The test requirements are sufficiently high to provide a level of confidence that any manufacturing or construction defects or integrity threats will be discovered for the vast majority of piping.

The emphasis for spike testing comes from an NTSB safety recommendation. Specifically,

Amend Title 49 Code of Federal Regulations 192.619 to delete the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.

AGA has the upmost respect for the NTSB and its investigative expertise. The NTSB openly stated that it is not their role to write regulations or operate pipelines. NTSB also stated they are open to alternative approaches to their recommendations. AGA believes that there are better regulatory alternatives than adopting the NTSB recommendation verbatim. AGA believes a spike test is appropriate for very specific applications and could negatively impact the safety of a line if used inappropriately. AGA has provided regulatory language that does not delete the grandfather clause as suggested by the NTSB, but instead amends the regulation to force all untested transmission pipe in HCAs at greater than 30% SMYS to be test, inspected by ILI or have its pressure reduced by 20%.

A spike test is a material strength determination procedure that is useful in very specific situations where crack-like defects are expected to exist such as stress corrosion cracking, selective corrosion of Electronic Resistance Welded (ERW) seams, and seam fatigue cracks. Other variables that should be considered prior to a spike test are pipe fatigue and the pipe environment. The IVP as it stands requires a spike test for all hydrostatic tests. AGA believes the specific characteristics of the pipe and the purpose of the test should be considered.

There have been comprehensive studies performed outlining hydrostatic testing and the appropriate uses of spike testing by engineers from Kiefner and Associates and also by DOT/RSPA. Most of the studies advocate spike testing in very limited situations and for pipe with certain integrity characteristics.
Rosenfeld from Kiefner and Associates states\textsuperscript{2} that a spike test is beneficial to determine crack-like defects but is unnecessary in the following circumstances:

- When standard operating pressure is below 40% SMYS
- When pipe being testing is new and of known good quality
- Where the purpose of the test is to demonstrate the strength of the pipe where crack-like defects are not expected to be present

A 2004 report by DOT/RSPA cautions use of spike testing on low frequency electric-resistance welded pipe (LF-ERW) using the formulae outlined in the report:

"Engineering judgment should be applied before using these formulae when considering a pipeline containing segments of low-frequency electric-resistance welded (LF-ERW) pipe, since testing such lines to 100 percent of SMYS may result in excessive numbers of failures, and therefore careful consideration of the actual desired operating pressure should be made\textsuperscript{3}\n
The report also states that a universal reassessment interval should not be defined due to degradation of structural integrity from frequent testing and pressure reversals (defeating the purpose of integrity testing). A paper by Kiefner and Maxey of Kiefner Associates\textsuperscript{4} advocates for spike testing, but also states that ILI is often a better alternative to pressure testing:

\textit{The most important reason why a hydrostatic test may not be the best way to validate the integrity of an existing pipeline is that in-line inspection is often a better alternative. From the standpoint of corrosion-caused metal loss, this is most certainly the case.}

\textit{From the standpoint of other types of defects, the appropriate in-line-inspection technology is evolving rapidly and, in some cases, it has proven to be more effective than hydrostatic testing.}

Some operators will use a spike test during their hydrostatic test work, but safety requires that individual operators make that decision based upon their individual circumstances and the characteristics of the pipe being tested.

\textsuperscript{2} "Hydrostatic pressure spike testing of pipelines – Why and When?" MJ Rosenfeld, Kiefner and Associates
\textsuperscript{3} Integrity Management Program Delivery Order DTRANS-02-D-70036 – Spike Hydrostatic Test Evaluation – Dept. of Transportation, Research and Special Programs Administration, Office of Pipeline Safety.
\textsuperscript{4} The Benefits and Limitations of Hydrostatic testing – John F. Kiefner & Willard A Maxey
G. Pipeline Record Verification

The first steps in the IVP process begin with record verification. PHMSA inferred at the IVP workshop that it believed that operators should have complete records for each category of MAOP record methodology and if all categories are not complete the operator should use 192.619(c) as the category to establish the MAOP. AGA believes that operators have implemented 49 CFR 192.619 and kept records of the lowest of the MAOP method category that was available at the time that the MAOP was established. Operators strive to have traceable, verifiable and complete records, but there will be gaps. Incomplete records do not mean that the records are insufficient to safely establish the MAOP.

AGA does not believe it is beneficial to have extensive discussion regarding more than 40 years of MAOP record keeping requirements. Instead, we want to focus on the actions that can reasonably be taken to remove the “grandfather clause” and implementing more testing or inspection for more miles of pipelines. That said, it is important for the docket to highlight the basic history of the original federal pipeline safety regulations contained in 49 CFR 192.607 Initial determination of class location and confirmation or establishment of maximum allowable operating pressure.

AGA respectfully disagrees with the presentation by PHMSA at the August 7 workshop regarding data that was submitted by operators on the 2012 Gas Transmission Annual Report. The information on the selection of the MAOP method used by operators to establish the MAOP is not granular enough to conduct a statistical analysis and draw conclusions, such as those in the PHMSA presentation. Additionally, PHMSA’s description regarding how operators used the historic five-year operating pressure and grandfather clause to establish the MAOP does not reflect the detailed engineering analysis conducted by operators and the Office of Pipeline Safety (OPS) when federal regulations came into existence. At that time, there was no blanket grandfathering of existing pipelines operating MAOPs. There was a very thoughtful, well-engineered transition from state pipeline safety regulations for establishing MAOPs to a uniform federal structure.

After a risk assessment and significant public debate, the first 49 CFR 192.619 was adopted in conjunction with 49 CFR 192.607 allowing a transition time for pipeline segments that were deemed to not be commensurate with the new design requirements to either be replaced, tested or the MAOP established at a lower level than the design pressure. Pipeline segments that were deemed a lower risk (MAOP<40% SMYS, Class 1 segments) and pipelines with a design pressure that was commensurate with the new class location definition were excluded from this activity. The regulations required that pipeline segments that were not commensurate had to pass through the new design based criteria under the 192.619(a) sections. Additionally, even if operators decided to establish the MAOP method
using 192.619(c), they had to comply with 192.611 Changes in class location: confirmation or revision of maximum allowable operating pressure.

Relevant portions of the interpretation from PHMSA states,

The "grandfather" clause in Section 192.619(c) permits continued operation of pipelines at existing operating pressures. However, this paragraph also refers to Section 192.611 and thus is qualified by the requirements for confirmation or revision to the extent that the higher pressures are not commensurate with the existing class location of the pipeline. The opinion quoted in the OPS Advisory Bulletin explains this relationship between the "grandfather" clause and the operating pressures provided for under Section 192.611. In that opinion, only pipelines that are presently in Class 1 locations would be exempt from having to be confirmed or revised in accordance with Section 192.611 if the operating pressure is not commensurate with the class location.\(^5\)

PHMSA removed 192.607 from the regulation in 1996 constructively acknowledging that operators complied with federal requirements to establish the MAOP and the agency was satisfied with the records that operators maintained for their MAOPs.

It was important for PHMSA to create Part Q of the annual transmission report to meet the Congressional requirements of section 23(a – c). MAOP record data submitted in the 2012 transmission annual report will provide a general understanding of the miles of pipe in each MAOP determination method outlined in 49 CFR §192.519.

It is recognized that a pipeline segment may have MAOP records in most of the categories of §192.619, but the completeness in each category may vary. There will also be variations among different operators due to system ages, company mergers and acquisitions. It is important to note that reporting incomplete records in one category does not necessarily mean that records are insufficient for MAOP determination. This was acknowledged by PHMSA in its response to AGA’s letter of June 28, 2012 that sought clarification that a single quality document that contains the information needed to confirm a pipeline’s MAOP would satisfy the intent of PHMSA’s Advisory Bulletin on traceable, verifiable and complete records (see Exhibit 4). Additionally, there is no way to separate pre-1970 from post 1970 information in Part Q. AGA believes that the assumptions PHMSA presented at the IVP workshop regarding Part Q data and the estimated miles that should be have been listed in 192.619(c) cannot be accurately discerned from the 2012 Transmission Annual Report because the information does not have sufficient granularity.

\(^5\) Interpretation 192.607 7, Mr. Caldwell (OPS) to Mr. Barry (Pioneer Natural Gas Company) December 9, 1971
AGA believes that the information collected in Part R of the transmission report is more valuable to MAOP testing regulations than Part Q. Because of the concise nature of reporting requirements, information on pressure testing is more accurate and reliable than Part Q. The AGA study on MAOP testing used the data that was developed from Part Q and R submissions and found the Part R data the most beneficial for completing the MAOP testing study. There are operators that followed regulations as they existed in 1971 that placed pipe in MAOP category 192.619(a)(3), using the five-year operating history, even if they did not have complete records in each MAOP category. Some might argue that MAOP category 192.619(c) should have been used in these instances. The engineering justification of 192.619(a)(3) and 192.619(c) would have been the same five-year operating history and there is no material difference in the operation of the pipeline. The language AGA suggested amending 192.619 and the MAOP testing study discussed previously treats pipe without a pressure test in the same manner regardless of the Part Q MAOP category that it is listed.

H. Expansion of Gas Transmission Integrity Management

AGA supports the thoughtful, effective expansion of natural gas transmission integrity management. However, AGA believes other actions must first take place. This includes analyzing the performance of the first ten years of transmission integrity management, reviewing PHMSA’s report to Congress on expanding integrity management or integrity management elements, hearing from the legislators and considering the impact of pressure testing, replacement, ILI, pressure reduction or abandonment of untested natural gas transmission pipelines operating at greater than 30% SMYS in HCAs. Section 5 of the Pipeline Safety Act of 2011 gives very specific direction on evaluating integrity management expansion, reporting to Congress and provides restrictions on promulgating a final regulation. (See Exhibit 5 – Excerpt from the Pipeline Safety Act of 2011)

AGA does not want to impede the promulgation of a final rule on the expansion of integrity management principles outside of HCAs. AGA simply believes other actions must be taken first and there are a number of questions that remain unanswered. For example: What are the strengths and weaknesses of the program? What is PHMSA’s evaluation of the program? What recommendations will Congress make to the Secretary of Transportation? What are the potential adverse consequences of attempting to implement an expansion to gas transmission integrity management at the same time operators are attempting the implement an MAOP testing program that is more than 10 times the magnitude of the original gas transmission integrity management program?

Finally, AGA notes there will be over-testing in non-HCA areas during MAOP verification because hydrostatic testing or ILI begin and end at logical valve locations regardless of the
formation of HCAs. After a significant portion of the MAOP verification in HCAs is complete, operators will be able to assess how to perform testing in the remaining areas of class 3 and 4 locations.

AGA is convening a meeting of several dozen operators in October 2013 to specifically discuss the feasibility of expanding gas transmission integrity management. There are no ex parte barriers to PHMSA participating in the meeting and we would welcome its presence to inform operators of its findings and thoughts on expanding the program.

III. Conclusion

AGA commends PHMSA's continuing commitment to pipeline safety and it appreciates the opportunity to comment on the PHMSA draft IVP. Safety is AGA's number one priority. AGA and other industry representatives are in unanimous agreement that MAOP testing should be separated from the expansion of gas transmission integrity management. The two processes have completely separate objectives and their integration into a single process creates unnecessary confusion and complexity.

To move the regulatory process forward, AGA has offered regulatory language that implements Congressional mandates, is consistent with PHMSA regulations and current industry practices, and uses proven technology. Some operators are already implementing the mandates in section 23(d) of the Pipeline Safety Act. AGA and its member companies want to go beyond the mandates in the Pipeline Safety Act of 2011 by testing all untested pipelines in Class 3 and 4 pipelines that operate at or above 30% SMYS. MAOP verification in HCAs must be accomplished before this expanded goal. and industry must assess the available engineering and construction resources, the impact on gas delivery, and other regulatory initiatives that PHMSA may propose.

If you need additional information please feel free to contact me.

Respectfully submitted,

Date: September 9, 2013

By: [Signature]

Christina Sames
For further information, please contact:

Christina Sames  
Vice President 
Operations and Engineering 
American Gas Association 
400 North Capitol Street, NW 
Washington, D.C. 20001 
(202) 824-7214 
csames@aga.org

Philip Bennett  
Senior Managing Counsel 
American Gas Association 
400 North Capitol Street, NW 
Washington, D.C. 20001 
(202) 824-7339 
pbennett@aga.org
As a result of the Pipeline Safety Act of 2011, natural gas operators are working to meet the Congressional requirement to ensure that all gas transmission pipelines operating above 30 percent Specified Minimum Yield strength (SMYS) in high consequence areas (HCAs) have a pressure test. AGA believes that each operator’s system is unique, and therefore, each operator will have a unique plan to address this requirement. It is believed that state regulators are best suited for addressing and approving these plans for local distribution companies.

The Legislation: The Pipeline Safety Act of 2011, Section 23(d) states “The Secretary shall...prescribe regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in areas identified pursuant to section 60109(a) of title 49, United States Code, and operating at a pressure greater than 30 percent of specified minimum yield strength.”

The Act also directs that “The Secretary shall consider safety testing methodologies including, at a minimum, pressure testing or other alternative methods, including in-line inspections, determined by the Secretary to be of equal or greater effectiveness.” Industry has provided regulators with outlines for appropriate methodologies to test pre-1970 pipelines that do not have records of pressure testing. The methodologies include conducting a pressure test to 1.25 times the Maximum Allowable Operating Pressure (MAOP), reducing the pressure to 80 percent of the established MAOP, replacing the untested pipeline segment, or running in-line inspection (ILI) devices that identify and characterize pipe anomalies.

American Gas Association (AGA) Position: AGA suggests a risk based approach to address transmission pipelines operating at greater than 30% SMYS in HCAs that have not undergone a post-construction pressure test. By starting with the lines representing the greatest risk, based upon their design and operating characteristics, maintenance history and operating SMYS levels, operators are complying with the intent of Congress.

AGA supports the use of a thoughtful and reasonable approach to safety testing methodologies for transmission pipelines operating at greater than 30% SMYS in HCAs. It recognizes that transmission pipeline operators manage unique systems, each with their own challenges, including costs and time constraints. It is understood that shutting down the natural gas transmission system compromises national security and economic health. Operators must address pressure testing while simultaneously maintaining reliable delivery of natural gas to millions of residential customers and many thousands of commercial and industrial businesses. Even with all of these challenges, AGA believes low prices for abundant natural gas make this the perfect time to invest in upgrading the natural gas pipeline infrastructure. AGA believes operators, regulators and the public need to engage in forums that allow for the transfer of ideas and concerns. The following initiatives are underway to aid in communication among impacted parties:

1. AGA and the Interstate Natural Gas Association of America (INGAA) are constructing flow charts and developing regulatory language that begins to address methodologies for addressing transmission pipelines that have not had a post-construction pressure test.

2. AGA and INGAA are working with research organizations on the viability of using internal inspection tools and other methods as alternatives to pressure testing of in-service transmission lines, pipeline replacement or reduction in operating pressure.

3. Operators are working with their appropriate state regulators to develop pipeline safety plans to address this congressional mandate. These plans will allow operators to maintain safe operation of their pipelines while remaining sensitive to the impacts to ratepayers and shareholders.

AGA Contact: Phil Bennett, (202) 824-7339, pbennett@aga.org; Erin Carmichael, (202) 824-7328, ecarmichael@aga.org
In the interest of safety, natural gas pipelines are required to be operated at conservative pressures under federal and state regulations. Conservative pressures represent the maximum pressure at which a pipe can operate, based on previous strength testing and engineering calculations, taking into consideration pipe properties and the surrounding population. Operators have compiled the Maximum Allowable Operating Pressure (MAOP) records of transmission pipelines and shown that, notwithstanding gaps in available information, the pipelines are operating at pressures as determined by regulations and sound engineering practices.

**Background:** Following the natural gas pipeline incident in San Bruno, CA on September 9, 2010, the National Transportation Safety Board (NTSB) made the following safety recommendation to the responsible utility Pacific Gas & Electric (PG&E): “aggressively and diligently search for all as-built drawings, alignment sheets and specifications, and all design, construction, inspection, testing, maintenance, and other related records, including those records in locations controlled by personnel outside the firm relating to pipeline system components, such as pipe segments, valves, fittings and weld seams for...natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had a MAOP established through prior hydrostatic testing. These records should be traceable, verifiable and complete (P-10-2).”

In response to AGA’s request for clarification on NTSB Recommendations P-10-1 through P-10-4, NTSB stated that AGA’s interpretations of NTSB’s intent for PG&E were correct. NTSB stated that it did not “intend for Federal or state agencies to codify the language from our safety recommendations directly into state and Federal rules and regulations.”

Although NTSB’s recommendations are specific for a single operator, the Pipeline Safety Act of 2011, Sec. 23 MAOP, outlined Congress’ requirement for operators to confirm MAOP records for gas pipelines in class 3 and class 4 locations and class 1 and class 2 high consequence areas (HCAs). To accomplish this, the U.S. Department of Transportation’s Pipeline and Hazardous Materials Administration (PHMSA) is requiring operators to submit MAOP verification data in the gas transmission annual report by June 15, 2013.

**American Gas Association (AGA) Position:** AGA believes that it is important for operators to strive to have traceable, verifiable, and complete transmission pipeline MAOP records. However, gaps in records do exist and pipeline safety regulations are designed for continued safe operation with incomplete records. MAOP records data submitted in the 2012 transmission annual report will provide a general understanding of the miles of pipe per MAOP determination method outlined in 49 CFR §192.619. It is recognized that a pipeline segment may have MAOP records in most of the categories of §192.619, but the completeness in each category may vary. There will also be variations among different operators due to system ages, company mergers and acquisitions. It is important to note that reporting incomplete records in one category does not necessarily mean that records are insufficient for MAOP determination. Current pipeline safety regulations are designed for operators to continue to safely operate pipelines in the event that records are not available by using conservative engineering estimates and obtaining supplemental information.

AGA believes there is a lack of understanding regarding how records were originally managed by pipeline operators to establish MAOP when the pipeline was initially built. Natural gas transmission pipelines were and continue to be designed, constructed and operated with conservative safety factors below a pipe’s engineered design pressure. Operators have compiled the MAOP records of these pipelines and shown that, notwithstanding gaps in available information, the pipelines are operating at pressures determined by sound engineering practices. Widespread testing or replacement of safely operating pipelines with incomplete MAOP records is not required by regulation and was not the intent of Congress. Mandating the widespread testing of in-service transmission pipelines can result in large outages and/or additional safety risks to the public.

**AGA Contact:** Phil Bennett, (202) 824-7339, pbennett@aga.org; Erin Carmichael, (202) 824-7328, ecarmichael@aga.org
EXHIBIT 4 - PHMSA’s Response Letter to AGA on MAOP Records

JUL 31, 2012

Ms. Christina Sames
Vice President, Operations & Engineering
American Gas Association
400 North Capitol Street, NW
Washington, DC 20001

Dear Ms. Sames:

In a June 28, 2012, email to the Pipeline and Hazardous Materials Safety Administration (PHMSA), you stated that members of the American Gas Association (AGA) are seeking clarification of PHMSA’s recent Advisory Bulletin regarding Verification of Records (ADB-12-06, Docket No. PHMSA-2012-00068). AGA’s question is whether a single quality document that contains the information needed to confirm a pipeline’s Maximum Allowable Operating Pressure (MAOP) or Maximum Operating Pressure (MOP) would satisfy the intent of the Advisory Bulletin.

The owner or operator of a pipeline must meet the recordkeeping requirements of Part 192 and Part 195 in support of MAOP and MOP determination. As you stated in your request, operators need to identify appropriate records that establish a high level of confidence regarding the pipeline’s MAOP or MOP, whether that record is a single quality record or information confirmed by other complementary, but separate, documents. Therefore, a single quality document that is traceable and complete, as evidenced by appropriate markings, would be acceptable.

I hope that this information is helpful to you. If I can be of further assistance, please contact me at 202-366-4046.

Sincerely,

John A. Gale
Director, Office of Standards and Rulemaking
EXHIBIT 5 – Excerpts from the Pipeline Safety Act of 2011

Sec. 5

(a) Evaluation.—Not later than 18 months after the date of enactment of this Act, the Secretary of Transportation shall evaluate—

(1) whether integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas; and

(2) with respect to gas transmission pipeline facilities, whether applying integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

(b) Factors.—In conducting the evaluation under subsection (a), the Secretary shall consider, at a minimum, the following:

(1) The continuing priority to enhance protections for public safety.

(2) The continuing importance of reducing risk in high-consequence areas.

(3) The incremental costs of applying integrity management standards to pipelines outside of high-consequence areas where operators are already conducting assessments beyond what is required under chapter 601 of title 49, United States Code.

(4) The need to undertake integrity management assessments and repairs in a manner that is achievable and sustainable, and that does not disrupt pipeline service.

(5) The options for phasing in the extension of integrity management requirements beyond high-consequence areas, including the most effective and efficient options for decreasing risks to an increasing number of people living or working in proximity to pipeline facilities.

(6) The appropriateness of applying repair criteria, such as pressure reductions and special requirements for scheduling remediation, to areas that are not high-consequence areas.

(c) Report.—Not later than 2 years after the date of enactment of this Act, the Secretary shall submit to the Committee on Transportation and Infrastructure and the Committee on Energy and Commerce of the House of Representatives and the Committee on Commerce, Science, and Transportation of the Senate a report, based on the evaluation conducted under subsection (a), containing the Secretary’s analysis and findings regarding—

(1) expansion of integrity management requirements, or elements thereof, beyond high-consequence areas; and

(2) with respect to gas transmission pipeline facilities, whether applying the integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

(d) Data Reporting.—The Secretary shall collect any relevant data necessary to complete the evaluation required by subsection (a).

(f) Rulemaking Requirements.—
(1) Review Period Defined.—In this subsection, the term “review period” means the period beginning on the date of enactment of this Act and ending on the earlier of—
(A) the date that is 1 year after the date of completion of the report in subsection (c); or
(B) the date that is 3 years after the date of enactment of this Act.
(2) Congressional Authority.—In order to provide Congress the necessary time to review the results of the report required by subsection (c) and implement appropriate recommendations, the Secretary shall not, during the review period, issue final regulations described in paragraph (3)(B).
(3) Standards.—
(A) Findings.—As soon as practicable following the review period, the Secretary shall issue final regulations described in subparagraph (B), if the Secretary finds, in the report required under subsection (c), that—
(i) integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas; and
(ii) with respect to gas transmission pipeline facilities, applying integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.
(B) Regulations.—Regulations issued by the Secretary under subparagraph (A), if any, shall—
(i) expand integrity management system requirements, or elements thereof, beyond high-consequence areas; and
(ii) remove redundant class location requirements for gas transmission pipeline facilities that are regulated under an integrity management program adopted and implemented under section 60109(c)(2) of title 49, United States Code.
(4) Savings Clause.—
(A) in General.—Notwithstanding any other provision of this subsection, the Secretary, during the review period, may issue final regulations described in paragraph (3)(B), if the Secretary determines that a condition that poses a risk to public safety, property, or the environment is present or an imminent hazard exists and that the regulations will address the risk or hazard.
(B) Imminent Hazard Defined.—In subparagraph (A), the term “imminent hazard” means the existence of a condition related to pipelines or pipeline operations that presents a substantial likelihood that death, serious illness, severe personal injury, or substantial endangerment to health, property, or the environment may occur.
(g) Report to Congress on Risk-Based Pipeline Reassessment Intervals.—Not later than 2 years after the date of enactment of this Act, the Comptroller General of the United States shall evaluate—
(1) whether risk-based reassessment intervals are a more effective alternative for managing risks to pipelines in high-consequence areas once baseline assessments are complete when compared to the reassessment interval specified in section 60109(c)(3)(B) of title 49, United States Code.
(2) the number of anomalies found in baseline assessments required under section 60109(c)(3)(A) of title 49, United States Code, as compared to the number of anomalies found in reassessments required under section 60109(c)(3)(B) of such title; and
(3) the progress made in implementing the recommendations in GAO Report 06-945 and the current relevance of those recommendations that have not been implemented.
Appendix E

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

Pipeline Safety: Public Workshop
on the Integrity Verification Process

Docket PHMSA-2013-0119

THE THIRD SET OF COMMENTS OF THE AMERICAN GAS ASSOCIATION
ON THE REVISED
PHMSA DRAFT INTEGRITY VERIFICATION PROCESS

The American Gas Association (AGA), founded in 1918, represents more than 200 local energy
companies that deliver clean natural gas throughout the United States. There are more than 71
million residential, commercial and industrial natural gas customers in the U.S., of which almost
92 percent - more than 65 million customers - receive their gas from AGA members. Today,
natural gas meets almost one-fourth of the United States' energy needs.

1. Introduction:

AGA appreciates the opportunity to comment on the revised PHMSA Draft Integrity Verification
Process (IVP). These comments supplement previous comments submitted by AGA and are not
a substitution of those previous comments or the material submitted with those comments.

The Pipeline and Hazardous Material Safety Administration (PHMSA) made a judicious decision
to present the draft IVP to the public and industry before issuing a proposed regulation. At this
stage, the revised IVP flow chart is merely a decision tree with no qualifying details, such as
pipeline mileage, potential supply impacts or cost information. Therefore, it does not depict the
millions of engineering man-hours and billions of dollars required to perform Maximum
Allowable Operating Pressure (MAOP) verification tests on previously untested natural gas
transmission pipelines\(^1\) or the impact of other elements proposed in the IVP flow chart. The IVP decision tree does provide an opportunity for the public, industry and regulators to agree on how to best implement Congressional mandates and some of the NTSB safety recommendations that are not in conflict with provisions of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pipeline Safety Act of 2011). Conversations with PHMSA have helped to clarify some issues regarding MAOP verification. AGA appreciates those conversations and was impressed by the flexibility expressed by PHMSA to make some of the elements of the proposed IVP less prescriptive and burdensome.

AGA’s comments summarize the areas where it believes there is agreement as well as the areas that need more discussion. The public had limited time to review and comment on the revised PHMSA draft IVP flow chart that was posted in the docket on September 11, 2013. Therefore, AGA’s comments do not cover all aspects of the revised IVP flow chart. AGA will hold a meeting with operators from across the country on October 17 and 18 and will submit additional comments concurrent with comments it will submit in response to PHMSA’s request for information on class locations. AGA believes the use or elimination of class locations is integral to integrity management and the IVP.

The Congressional mandate in section 23(d) of the Pipeline Safety Act of 2011 to require testing of untested transmission pipelines that operate above 30 percent of Specified Minimum Yield Strength (SMYS) in High Consequence Areas (HCAs) is a multi-billion dollar endeavor. It is several orders of magnitude larger than any regulation PHMSA has attempted to promulgate and larger than any group of construction projects attempted by the natural gas pipeline industry. An effort of this magnitude cannot be accomplished with a one size fits all federal safety regulation. AGA represents gas utilities which span all 50 states; representing diverse regions and operating conditions. PHMSA must recognize the significant role that state governing bodies will have in funding these actions. Each utility serves a unique and defined geographic area and their system infrastructures vary widely based on a multitude of factors.

\(^1\)See EN Engineering report, Evaluation of MAOP Testing for In-Service Transmission Pipelines, sponsored by AGA, August 6, 2013, for a realistic assessment of mileage and cost for various scenarios.
including facility condition, past engineering practices and materials. Each operator will need to evaluate the actions in light of system variables, the operator’s independent integrity assessment, risk analysis and mitigation strategy and what has been deemed reasonable and prudent by their Commissions. A federal safety regulation must be compatible with the legal obligation every public utility has to furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.

A general comment that should be considered in all discussions about MAOP verification and testing is that AGA believes that every natural gas pipeline in the United States of America has an MAOP established by the operator consistent with the provisions of 49 CFR Part 192. The methods used to establish the MAOP of pipelines have been in the federal pipeline safety code since 1971 and there were state regulations and/or industry consensus standards in effect to establish the MAOP before the federal code. Instead of using the phrase “establish MAOP” in the IVP flow chart and correspondence, AGA suggests that PHMSA use the phrases “verify MAOP” or “confirm MAOP” to reflect the fact that the MAOP has previously been determined. There are important legal ramifications associated with the use of these phrases.

As noted in previous comments submitted by AGA, AGA believes it is inappropriate to use the term “traceable, verifiable and complete” (TVC) records as a statutory standard. The National Transportation Safety Board (NTSB) made a specific safety recommendation to an intrastate operator in its report on the natural gas pipeline incident in San Bruno, California\(^2\) which used the term TVC records. This was the first time that term was used. Following the release of this

\(^2\) Pipeline Accident Report: Pacific Gas and Electric Company - Natural Gas Transmission Pipeline Rupture and Fire - San Bruno, California - September 9, 2010, p. 133, NTSB/PAR-11/01: PB2011-916501: Notation 8275C (NTSB Aug. 3, 2011)(NTSB Recommendation P-10-2 called for PG&E to “[a]gressively and diligently search for all [records] relating to pipeline system components . . . in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had an MAOP established through prior hydrostatic testing, and stated that these records should be “traceable, verifiable, and complete.”).
NTSB report, PHMSA referenced TVC records in its Advisory Bulletin ADB-11-01\(^3\), issued January 4, 2011. In this advisory bulletin, PHMSA suggested that TVC was the mandatory standard for MAOP record sufficiency. That position is inconsistent with current regulations and past guidance issued by PHMSA pertaining to records.

It should be noted that in the interest of safety, many AGA member companies are already proactively taking actions to implement the MAOP verification testing requirements of the Pipeline Safety Act of 2011. The record review requirements of section 23(a–c) have been completed for High Consequence Areas (HCAs) and operators are continuing the record review of all transmission pipelines. Some operators have completed this process. The three intrastate transmission operators in California have submitted Pipeline Implementation Plans to the California Public Utilities Commission for approval. AGA is aware of operators in other jurisdictions that have begun MAOP verification testing of untested in-service transmission pipelines, or are allocating funds and developing plans that will be submitted to utility commissions for approval. Other operators are hesitant to take action pending an indication from PHMSA regarding what actions will be accepted to verify or confirm the MAOP of previously untested transmission pipelines in HCAs and the extent of required actions. In effect, the complexity and uncertainty involved in the revised PHMSA IVP is inadvertently delaying operator action to test pipelines due to their concern that the work may be nullified if it does not conform to the as yet undefined federal regulation. AGA hopes that PHMSA reviews the areas of agreement, as noted in AGA’s comments, and promotes a clear and concise framework, consistent with established industry safety practices that can be used by operators to implement safety enhancements before a final rule is promulgated.

Finally, more discussion is needed regarding the concept of moderate consequence areas (MCAs) and the timing to implement a proposed regulation. There are valid technical justifications to extend regulatory process from high consequence areas to moderate consequence areas, such as extending integrity management principles to transmission

pipelines outside of HCAs. However, establishing requirements to test previously untested transmission pipelines outside of HCAs or below 30% SMYS would immediately bring thousands of miles of lower risk and lower consequence pipelines into this enhanced regulatory process, dramatically increasing the cost to customers, impact to operators and timeline to implement. Actions to test previously untested transmission pipelines operating in HCAs, where the impact of a release is expected to be more significant, and to pipelines operating above 30% SMYS, a point above which pipelines typically fail instead of leak, should be the primary focus. Operators have explained that it will take 10 to 15 years to complete MAOP verification testing in HCAs. There are fundamental logistical problems attempting to define the impact on a single home when Local Distribution Company (LDC) transmission pipelines are embedded in a distribution system with almost 70 million. AGA believes the concept of MCAs can provide advantages to managing safety in interstate pipelines that can more readily rely on house count information. There will be ample opportunity to address the MCA concept after Congress, regulators, the public and industry have evaluated the early years of implementing the IVP process for lines above 30% SMYS in HCAs.

II. Detailed Comments
A. Areas of Agreement

Pressure testing: Pressure testing is the single most valuable method for MAOP verification testing. A pressure test is more effective than record verifications or material validation because it provides physical data from the field on the strength of the pipeline and information about potential safety issues that are not readily apparent. A pressure test does not require an operator to have information on whether a line has issues such as cracks, seam failure, corrosion, or subgrade steel within the pipeline. If the pipeline and appurtenances do not have the material strength to withstand the pressure test, the material will fail. In essence, it is the ultimate litmus test to validate what an operator knows about its pipeline.

AGA is in agreement with PHMSA that spike testing is not needed during all pressure tests, particularly in lower stress pipelines where there is great separation between MAOP and SMYS.
The NTSB recommendation on pressure tests did not have restrictions, but it is not the responsibility of the NTSB to craft recommendations with specificity to be codified. For pipelines that are susceptible to crack or seam failure, a higher percent SMYS pressure test should be performed consistent with established integrity management standards. When appropriate, this integrity management inspection may be performed in conjunction with MAOP verification testing.

It is also important to clarify that when Congress mandated that PHMSA develop a testing regulation to test the material strength of untested pipe operating at greater than 30 percent SMYS in HCAs, Congress directed the testing of the material strength to be determined by a pressure test, not material analysis to determine the tensile strength or chemical composition of the steel itself. The language in the statute is clear that the intended scope is defined as pipe that has not had a post-construction pressure test. Additionally, the term “material strength” has been used in 49 CFR 192 to mean a pressure test, (See §192.505 Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS; §192.501 Scope. This subpart prescribes minimum leak-test and strength-test requirements for pipelines).

Section 23(d) TESTING REGULATIONS.—
“(1) IN GENERAL.—Not later than 18 months after the date of enactment of this section, the Secretary shall issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in high-consequence areas and operating at a pressure greater than 30 percent of specified minimum yield strength.
“(2) CONSIDERATIONS.—In developing the regulations, the Secretary shall consider safety testing methodologies, including, at a minimum—
“(A) pressure testing; and
“(B) other alternative methods, including in-line inspections, determined by the Secretary to be of equal or greater effectiveness.

Finally, AGA believes it and PHMSA are in agreement that a single pressure test at 1.25 times MAOP during a pipeline’s life adequately establishes a pipeline’s strength for purposes of establishing a valid MAOP. This one-time pressure test establishes a safety margin between the test pressure and the operating pressure (that is maintained for the life of the pipeline).
Conversely, integrity management is a repetitive, continual process. By statute, the gas transmission integrity management assessment must be performed within every seven years. These are fundamental reasons why MAOP verification and integrity management have to be separated during the IVP development and rulemaking process.

**Material Validation:** AGA agrees with PHMSA that material should be tested when pipelines are exposed and shutdown for repair. The overwhelming majority of pipeline segments have complete records documenting how the MAOP was established. PHMSA's Gas Transmission Annual report for 2012 shows that 94.7 percent of the pipeline mileage has complete records for a MAOP method category. That does not tell the entire story. The MAOP pressure test records for a pipeline segment may be incomplete, but the same segment may have design records to support the established MAOP. Even when the operator does not have a verifiable record on each foot of pipeline, they generally are confident about the pipe specification and can make conservative assumptions to safely operate the pipeline. It is appropriate to gather information on the material of a line when the pipeline is exposed, shutdown for repair or removed from service.

AGA does not believe that material validation is a "long term statistical program." It is a long term program that validates, through field sampling, that pipe specifications in an operator's records are accurate. Material verification is also an important component when performing an In-Line Inspection (ILI) in lieu of a pressure test for MAOP verification.

**B. Areas Where More Discussion is Needed**

**Moderate Consequence Areas:** As explained earlier, AGA believes the concept of MCAs should be considered through expansion of integrity management principles to areas outside of HCAs. There will be ample opportunity to address pressure testing of transmission pipelines in MCAs after Congress, regulators, the public and industry have evaluated the early years of implementing the IVP process in HCAs.
The concept of using MCAs does not work when prioritizing the testing sequence for transmission pipelines operated by local distribution companies. The revised PHMSA IVP consequence area screening prioritization uses the following mileage:

100% class 4
100% class 3
100% class 2
50% class 1 (This is the AGA member estimate for one house in an impact circle)

The amount of pipe that would result in a “Yes” answer to box one in the revised PHMSA draft IVP represents 75 percent of the total transmission mileage operated by LDCs, which is a 600 percent increase over the mileage covered by the current HCA definition being applied by industry. AGA members have approximately 55,000 miles of transmission pipelines, of which approximately 45,000 miles of pipeline will be impacted by the revised draft PHMSA IVP process and only 10,000 miles would continue to operate under existing 49 CFR 192 regulations. The tragic San Bruno accident occurred in an HCA. AGA and its member companies believe the IVP should focus resources on pipelines where an incident is expected to have a greater consequence - pipelines in HCAs that are operating above 30% SMYS.

A better alternative to the inclusion of MCAs in the IVP process is to simply require operators to develop a plan that prioritizes transmission pipeline segments that need MAOP verification tests and specify a completion deadline. These plans would be submitted to PHMSA or the state pipeline safety office that provides oversight of the operator’s pipeline safety activities. The transmission pipelines operated by LDCs are embedded within the distribution system and are different than interstate transmission pipeline systems. Operators will use many factors to prioritize verification testing including HCAs, class location, pipeline stress levels, pipe material, type of construction, environment, date of installation, and whether testing requires the use of temporary LNG or CNG supplies to continue to provide reliable natural gas service to customers.
Experience has shown that industry will implement integrity management assessments and make repairs in non-HCA areas at least three times the order of magnitude than in HCAs. This is because non-HCA areas are larger and operators allocate resources through over-testing more efficiently than with prescriptive regulation. Simply stated, it is easy to use ILI or pressure tests for long segments that include HCA and non-HCA areas. It is more difficult and costly to attempt to perform only HCA assessments or testing first; and then schedule work for MCA or non-HCA areas. Exhibit 1 is an example of data AGA collected from operators in 2011. AGA believes that PHMSA has similar data in its transmission integrity management database. Exhibit 2 has photos showing how complicated the HCA concept is for LDC transmission. The MCA concept will be even more complex for LDC transmission pipelines.

The scheduling of pressure testing of untested pipelines is not solely a safety issue. Rather, it is a safety, legal and a resource allocation issue. AGA believes that, ideally, all untested pipe should be tested. However, Congress mandated that the Secretary of Transportation focus pressure testing on pipelines located in HCAs and operating at stress levels higher than 30 percent. Congress understood that operators cannot test thousands of miles of pipelines quickly and wanted resources to be placed where they would make the greatest impact. Congress will review the Pipeline Safety Act in 2015. At that time they will see how much progress has been made in MAOP verification testing and may decide to adjust the priority assigned to lower stress pipelines and non-HCA areas.

AGA will provide more comments regarding the complexity of using HCAs and MCAs for LDC operations with its comments on the request for information on class location.

**Low Stress Pipelines:** PHMSA asked AGA to provide suggestions regarding how to address small diameter transmission pipelines, because PHMSA views these as lower risk pipelines and it was not the intent of the revised IVP to focus on these pipelines. The SMYS of a gas transmission pipeline is directly proportional to the diameter and operating pressure and inversely proportional to the wall thickness and yield strength.

\[ P = (2St/d) \times F \times E \times T \]
When AGA supports focusing the revised IVR on transmission pipelines operating above 30 percent SMYS, it is inherently suggesting segregation of pipe with lower pressures, smaller diameters, and stronger walls that present a lower risk to the public. Low stress pipelines have historically been defined as those operating at or below 30 percent SMYS (see §192.941). In PHMSA’s Final Rule for Integrity Management for Gas Transmission Pipelines, PHMSA stated “the final rule recognizes that low stress pipeline (i.e., that operating below 30% SMYS) is different from pipeline that sees higher stresses. Low-stress pipeline tends to fail by leakage rather than rupture.” This demarcation at 30 percent SMYS is also consistent with the Pipeline Safety Act of 2011, where Congress specifically requested “regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in high-consequence areas and operating at a pressure greater than 30 percent of specified minimum yield strength.” AGA supports the continued delineation between low stress and high stress gas transmission pipe at 30 percent SMYS.

It is critical for PHMSA to understand the unique challenges faced by AGA member companies. In many situations, low stress transmission pipelines operated by distribution companies are completely embedded into the full, complex distribution system. It will be much more difficult to pressure test or perform ILI assessments on these pipelines compared to rural transmission pipelines. Throughout the country, transmission pipelines operated by LDCs directly feed subdivisions, industrial parks, businesses, small cities and villages. Many of these pipelines are one-way and the single source of gas, requiring temporary bypasses or LNG/CNG trailers to be used to maintain gas service. In addition, many of these lines operate at lower pressures; have multiple valves and offshoots, and bends that make it difficult to impossible to remove water from the line if a hydrostatic test is conducted. Operators will need to identify alternatives regarding how and when to perform the in-service testing or replacement in order to meet regulations. Often these low stress lines are defined as transmission due to state rules and not due to their operation at high pressures or transporting large volumes of natural gas. In such situations, they present a lower risk and should be prioritized as such.

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Critical Engineering Assessment AGA will not agree or disagree with what PHMSA is requesting in Box 6 of the IVP, Engineering Critical Assessment (ECA). The box contains some good engineering concepts, but the purpose of, and how to implement these concepts, is not clear. The revised IVP ECA option uses measures that are predominantly used as a part of integrity assessments. For instance, CIS, Coating Surveys and Interference surveys are typically tools that are a part of the External Corrosion Direct Assessment (ECDA) process. AGA believes that PHMSA should focus on the necessary criteria for establishing equivalency between pressure tests and ILI. The criteria should display ILI’s effectiveness in identifying manufacturing and pipe construction-related defects that are exposed during pressure tests.

The ability to use ILI in lieu of a pressure test is a much more important undertaking than reviewing MAOP records for material verification. Records reviews and material verification focus on confirming information already known by the operator. In many respects, ILI provides equal or greater opportunity to enhance safety than pressure testing. Unlike a hydrostatic test, which is simply pass/fail, ILI reveals information about the condition of the pipe, including sub-critical anomalies. AGA is having periodic discussions with research organizations and we are confident that we can ultimately reach engineering consensus on ILI detection of a defect that is equivalent to a 1.25 * MAOP pressure test for various grades of pipe. However, there is no established regulatory vehicle to incorporate that kind of consensus into regulation in a timely fashion. To expedite the adoption of a consensus standard, AGA believes that government and industry should engage an independent third party, well respected for its engineering expertise and with no potential investment in the use or non-use of ILI in lieu of pressure tests, to be the judge of the threshold demonstrated ongoing research projects.

Industry Draft IVP Chart
AGA worked with INGAA to develop a chart that addresses the issues raised by PHMSA in a manner that is consistent with industry practices. PHMSA will find that there are some minor differences in the IVP chart developed by AGA and INGAA. This is reasonable because there are some fundamental differences between interstate and intrastate transmission pipelines that
PHMSA should address when proposing a regulation. It is not appropriate to arbitrarily apply the same regulatory requirements to all pipelines. It is not AGA’s intent to say that its decision tree chart is better than that proposed by PHMSA. PHMSA’s IVP chart was used for the foundation of the industry chart. The decision tree forms the basis for discussion to resolve through notice and comment once the regulatory language of a proposed rule is promulgated. Exhibit 3 presented is a simplified version of what is necessary for MAOP verification. The chart was designed with some fundamental principles.

- Follow the decision logic in the PHMSA IVP, except to separate any expansion of integrity management from the decision tree.
- Follow the congressional mandate to focus MAOP verification testing on high consequence areas and pipelines higher than 30% SMYS. AGA believes that this is consistent with NTSB recommendations for hydrotesting transmission pipelines that have not been pressure tested and for removal of the MAOP grandfather clause. Using this screening early in the decision process is the only way to eliminate the smaller diameter, lower diameter pipe that PHMSA did not want included in the IVP.
- The chart follows the NTSB safety recommendation to address manufacturing and construction defects with a 1.25 times MAOP pressure test.
- The chart acknowledges that portions of the transmission infrastructure have no record of a pressure test or the pressure test was less than 1.25 times the MAOP. The chart uses ILI technology to inspect for pipe defects, long seam and girth weld anomalies that would survive a 1.25 times MAOP pressure test. It is important for material records to be validated in conjunction with non-destructive ILI testing. This material verification is less important if the destructive pressure test is used.
- It is important to note that experience has shown that MAOP over-testing usually encompasses three to five times the mileage in non-HCAs than HCAs. This important information should be reported to PHMSA annually to document progress in assessing for the entire nation’s pipeline infrastructure.
- State laws that govern LDCs will require that state utility commission adopt the federal regulation. Additionally, state and federal laws that governor investor owned utilities will require capital projects to be conducted through rate case proceedings. This is vastly
different from the transmission Integrity Management Program that was comprised almost entirely of Operations & Maintenance assessments.

- A rough estimate of implementation timing is 12 years to complete the process. The chart is consistent with MAOP verification testing practices already being implemented by operators, so existing work will not be nullified and more operators can commence the work if a PHMSA proposed rule is consistent with the framework.

**Miscellaneous Issues**

There are a few additional issues that may need attention by PHMSA. The docket includes Frequently Asked Questions (FAQs) that are based on PHMSA’s original IVP and some of the answers are not correct. At this point in time, regulations have not been issued and FAQs are unnecessary. AGA suggests that the FAQs be removed and not posted until there is a consensus on a “relatively concrete” regulatory framework.

The revised version of the PHMSA draft IVP proposed to codify advisory bulletins ADB 11-01 and ADB 12-06. AGA suggests that PHMSA avoid attempting to codify advisory bulletins. PHMSA states on its website, “PHMSA uses advisory bulletins to inform affected pipeline operators and Federal and state pipeline safety personnel of matters that have the potential of becoming safety or environmental risks.” It should also be noted that there are portions of ADB 11-01 and ADB 12-06 that contradict each other.

**III. Conclusion**

AGA commends PHMSA’s continuing commitment to pipeline safety and it appreciates the opportunity to comment on the revised PHMSA draft IVP. Discussions with PHMSA have been helpful in understanding what PHMSA is trying to accomplish given the multiple mandates from Congress and numerous safety recommendations from the NTSE. AGA does not believe all of these objectives can be incorporated verbatim in a single process. AGA believes that PHMSA can develop a simplified framework that promotes the intent of all of the objectives.

Safety is AGA’s number one priority. To move the regulatory process forward, AGA has offered regulatory language that implements Congressional mandates, is consistent with PHMSA regulations and current industry practices, and uses proven technology. Some operators are already implementing the mandates in section 23(d) of the Pipeline Safety Act. AGA has submitted the *Evaluation of MAOP Testing for In-Service Transmission Pipelines* by EN Engineering to allow PHMSA to complete the cost-benefit analysis that must accompany a final rule. AGA has provided summaries of areas where there is agreement regarding implementation of elements in the IVP process and provides potential solutions for areas where more work is needed.

Respectfully submitted,

Date: October 9, 2013
AMERICAN GAS ASSOCIATION

By: __________________________
Christina Sames

For further information, please contact:

Christina Sames
Vice President
Operations and Engineering Management
American Gas Association
400 North Capitol Street, NW
Washington, D.C. 20001
(202) 824-7214
csames@aga.org

Philip Bennett
Managing Senior Counsel
Operations Safety
American Gas Association
400 North Capitol Street, NW
Washington, D.C. 20001
(202) 824-7339
pabennett@aga.org
### Exhibit 1 – AGA 2011 Survey of Integrity Management in HCAs and Non-HCAs

<table>
<thead>
<tr>
<th>Baseline</th>
<th>Count</th>
<th>Represented</th>
<th>TOTAL</th>
<th>Maximum</th>
<th>Minimum</th>
<th>Median</th>
<th>Mean</th>
</tr>
</thead>
<tbody>
<tr>
<td>Miles Assessed due to IMP - ILI</td>
<td>26</td>
<td>28,761</td>
<td>1,143</td>
<td>347.9</td>
<td>0.0</td>
<td>7.5</td>
<td>44.0</td>
</tr>
<tr>
<td>Miles Assessed due to IMP - Hydro</td>
<td>26</td>
<td>28,761</td>
<td>162</td>
<td>75.0</td>
<td>0.0</td>
<td>0.0</td>
<td>6.2</td>
</tr>
<tr>
<td>Miles Assessed due to IMP - DA</td>
<td>26</td>
<td>28,761</td>
<td>730</td>
<td>281.0</td>
<td>0.0</td>
<td>10.9</td>
<td>28.1</td>
</tr>
<tr>
<td>Total Miles of Pipeline Inspected this period due to IMP - Non-HCA</td>
<td>26</td>
<td>28,761</td>
<td>1,485</td>
<td>317.3</td>
<td>0.0</td>
<td>17.3</td>
<td>57.1</td>
</tr>
<tr>
<td>Total Number of repairs due to IMP - HCA</td>
<td>26</td>
<td>28,761</td>
<td>553</td>
<td>112.0</td>
<td>0.0</td>
<td>14.2</td>
<td>21.3</td>
</tr>
<tr>
<td>Total Number of repairs due to IMP - Non-HCA</td>
<td>26</td>
<td>28,761</td>
<td>1,079</td>
<td>925.0</td>
<td>0.0</td>
<td>0.0</td>
<td>41.5</td>
</tr>
<tr>
<td>Total feet of pipe replaced this period due to IMP - HCA</td>
<td>26</td>
<td>28,761</td>
<td>184</td>
<td>31.0</td>
<td>0.0</td>
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<td>7.1</td>
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<td>28,761</td>
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<tr>
<td>Total feet of pipe replaced this period due to IMP - HCA</td>
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<td>7,569</td>
<td>3,600.0</td>
<td>0.0</td>
<td>0.0</td>
<td>291.1</td>
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</table>
Exhibit 2 – The Complexity of Tracking HCAs in LDC Transmission

Overlapping HCAs
Exhibit 2A – The Complexity of LDC Transmission

24” pipeline
45° ell down
90° ell into shoring box
AGA’s Integrity Verification Process

ONE-TIME PROCESS to Test Previously Untested Transmission Pipelines

1. Identify pertinent state-specific rules that exceed Part 192 & impact IVPP

Start IVP

2. Is segment in HCA?

No

Yes

3. Is segment MAOP >50%?

No

Yes

4. Prior test >/= 1.25xMAOP w/ pressure test records. See note 1 & 3

Yes

No

5. Prior test >/= 1.1xMAOP w/ pressure test records

Yes

No

6. Select sensors to detect pipe body, long seam, and girth weld anomalies just surviving 1.25xMAOP test. Examine Anomalies per design factors (x1.25 or x1.5) respectively, and mitigate. See note 2

7. Derate Pipeline OR Replace Pipeline

8. Use ILI in lieu of pressure test and have material records?

Yes

No

9. Report all Non-HCA Pressure tested mileage and ILI mileage

10. Define cause and feed into M Risk Assessment

11. Test Failures?

Yes

No

12. Continue to Operate and Maintain in Accordance with Part 192 and Perform Integrity Management

Notes:

Susceptible Seam Types mean LFRW, SSAW, Flash Weld (AO Smith), or pipe w/ joint factor < 1 (e.g., lap welded pipe) regardless of date of manufacture with known history of long seam issues.

Non-susceptible Seam Types mean DSAW, HP-ERW, and Seamless

Note 1: Review 49 CFR 192.502 to require min. 1.25 MAOP pressure test for new pipe with design factor of 0.72

Note 2: Need to confirm material properties in order to respond to ILI results

Note 3: For the purposes of MAOP verification there is no limitation on allowable pressure test dates (pre-65 tests acceptable) or test durations.

Note 4: State will adopt federal regulation and actual implementation timing will be established by orders of utility commissions that require implementation plans for testing while minimizing customer outages

- Operator will annually submit mileage pressure tested in Non-HCA areas

Note 5: This is a decision tree. Regulatory flowcharts must use mileage and cost information to be technically feasible, reasonable, cost-effective, and practicable.

**Some state requirements exceed Part 192. For example:

- Pressure test at 150% MAOP to establish MAOP, or
- All gas transmission (GT) to be classified and constructed to Class 4 requirements, or
- Define as GT if MAOP>125 psig, etc.
The American Gas Association (AGA), founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 71 million residential, commercial and industrial natural gas customers in the U.S., of which almost 92 percent - more than 65 million customers - receive their gas from AGA members. Today, natural gas meets almost one-fourth of the United States’ energy needs.

I. INTRODUCTION

AGA appreciates the opportunity to comment on the revised PHMSA Draft Integrity Verification Process (IVP). These comments supplement previous comments submitted by AGA and are not a substitution of those previous comments or the material submitted with those comments. Conversations with PHMSA have helped to clarify some issues regarding MAOP verification and potential expansion of pipeline integrity management. AGA appreciates those conversations and was impressed by the flexibility expressed by PHMSA to make some of the elements of the proposed IVP less prescriptive and burdensome.

AGA’s third set of comments, submitted on October 8, 2013, summarized the areas where AGA believes there is agreement on aspects of the proposed IVP as well as the areas that need more discussion. AGA’s fourth set of comments focus specifically on low stress transmission pipelines operating at or below 30% of the Specified Minimum Yield Strength (SMYS). AGA provides suggestions that can enhance the safety of these pipelines consistent with the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (hereafter called the Pipeline Safety Act of 2011),
National Transportation Safety Board (NTSB) safety recommendations and studies by independent technical experts.

The suggestions included with these comments are based upon the relatively low risk posed by transmission pipelines operating at or below 30% SMYS. It is rare for a transmission pipeline operating below 30% SMYS to fail due to a manufacturing or construction defect, and low stress pipelines are prone to fail by leakage rather than rupture.\(^ {123} \) In the few instances where a low stress pipeline failed by rupture, the proximate causes were interactive threats such as long seam corrosion or latent third party damage from excavation. In these comments AGA suggests preventive and mitigative measures that will enhance the safety of low stress pipelines.

The Pipeline Safety Act of 2011 does not require MAOP verification testing for previously untested low stress transmission pipelines. In lieu of MAOP verification testing, AGA provides suggestions for safety enhancements for four categories of low stress transmission pipelines that operate at or below 30% SMYS and are located in High Consequence Areas (HCAs). The functional definition of transmission pipelines that operate below 20% should be excluded from MAOP testing because this definition includes plastic and steel mains as well as service lines that operate at low stress levels.

- **Pipelines with Susceptible Seam Types:** Transmission pipelines with susceptible seam types and where the operator has experienced a history of failure will need to have the pressure test records reviewed to confirm that the pipeline segment has been subjected to a test pressure of 1.25 times the MAOP or greater for a sufficient period of time to identify manufacturing and construction anomalies that could fail independently in operation.

- **Pipelines Without a Documented Pressure Test:** Transmission pipelines with no pressure test records must minimize the possibility of interactive threats. This can be accomplished by completing assessments for internal and external corrosion and confirming material records (in instances where material records are incomplete) through non-destructive testing and coupon and/or cylinder testing when the pipeline is taken out of service. The probability of a rupture is very low, but operators must ensure that they verify the pipe specification and use an integrity management process to confirm the integrity of the pipeline in accordance with Subpart O.

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\(^ {123} \) Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines); Final Rule, 68 Fed. Reg. 69795, December 15, 2003
• **Pressure Tested Pipelines**: Transmission pipelines with a pressure test record need no additional MAOP testing or integrity management measures beyond those required under Subpart O. Manufacturing and construction defects have already been addressed by the pressure test. The operator needs to continue to take action to minimize the threat of excavation damage because of the extensive excavation activity that typically occurs in HCAs.

• **Pipelines with a Small Potential Impact Radius (PIR)**: Transmission pipelines that have a PIR of less than 200 feet require no MAOP testing or additional integrity management measures beyond those defined in Subpart O. Pipelines with a small PIR are typically of smaller diameter and operate at lower pressures. An incident on these lines would result in a relatively small area of consequence even if the pipe suffered a failure by rupture. The operator needs to continue to take action to minimize the threat of excavation damage because of the extensive excavation that typically occurs in HCAs.

II. **DETAILED COMMENTS**

A. **Congressional Legislation and NTSB Recommendations**

When Congress wrote Section 23. Maximum Allowable Operating Pressure in the Pipeline Safety Act of 2011, it was concerned with the catastrophic failure of natural gas transmission pipelines by rupture. The relevant section states:

SEC. 23. MAXIMUM ALLOWABLE OPERATING PRESSURE.

§ 60139. Maximum allowable operating pressure

“(d) TESTING REGULATIONS.—

“(1) IN GENERAL.—Not later than 18 months after the date of enactment of this section, the Secretary shall issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in high-consequence areas and operating at a pressure greater than 30 percent of specified minimum yield strength.

“(2) CONSIDERATIONS.—In developing the regulations, the Secretary shall consider safety testing methodologies, including, at a minimum—

“(A) pressure testing; and

“(B) other alternative methods, including in-line inspections, determined by the Secretary to be of equal or greater effectiveness.

“(3) COMPLETION OF TESTING.—The Secretary, in consultation with the Chairman of the Federal Energy Regulatory Commission and State regulators, as appropriate, shall establish timeframes for the completion of such testing that take into account potential consequences to public safety and the environment and that minimize costs and service disruptions.

“(e) HIGH-CONSEQUENCE AREA DEFINED.—In this section, the term ‘high-consequence area’ means an area described in section 60109(a).”.
In Section 23, Congress used the term “Specified Minimum Yield Strength” for the first time and specifically required MAOP verification testing for previously untested transmission pipelines that operate in HCAs with a pressure above 30% SMYS. It was obvious to Congress that high stress pipelines above 30% SMYS that were previously untested should undergo hydrotesting, or an equivalent test procedure, to ensure that the threat of rupture is minimized.

Congress understood that low stress natural gas transmission pipelines were unlikely to fail by rupture. Since low stress pipelines are prone to leak rather than rupture, Congress did not require additional action to be taken on pipelines operating at or below 30% SMYS. The cost to hydrostatically test low stress pipelines already in service would require billions of dollars to be spent and would not improve pipeline safety. The suggestions provided by AGA satisfy the legislation and provide additional safety enhancements for a subset of low stress transmission pipelines.

Prior to passage of the Pipeline Safety Act of 2011, the NTSB issued safety recommendations regarding MAOP testing and manufacturing and construction defects that were written in relatively general terms. The recommendations are:

Amend Title 49 Code of Federal Regulations 192.619 to delete the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test. (P-11-14)

Amend Title 49 Code of Federal Regulations Part 192 of the Federal pipeline safety regulations so that manufacturing and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post construction hydrostatic pressure test of at least 1.25 times the maximum allowable operating pressure. (P-11-15)

AGA has the utmost respect for the accident investigative expertise of the NTSB. AGA supports the intent of the recommendations, but makes two important observations. First, it is not the responsibility of the NTSB to write safety recommendations in language precise enough to be codified in federal regulation. The general concepts stated in the recommendations must be revised to deal with the complexity of the nation’s natural gas infrastructure. As explained later, exemptions and alternatives must be provided to address these complexities. It is PHMSA’s responsibility to develop regulations that improve pipeline safety that are feasible, reasonable, practical and cost-beneficial. AGA has provided suggestions that we believe meet the intent of the NTSB recommendations and PHMSA’s regulatory responsibilities. Second, Congress saw the NTSB recommendations that were issued in August 2011 and drafted legislation that was passed in December 2011 that was narrower than the NTSB safety recommendations. Congress recognized that different transmission lines pose different risks and there are different ways to mitigate those
risks. Congress essentially modified safety recommendation P-11-14 to focus on the transmission pipelines that tend to fail by rupture, by requiring pressure testing of transmission pipelines that operate above 30% in HCAs. Congress also allowed for alternative testing, such as in-line instrument inspections.

The grandfather clause in 49 CFR 192.619 cannot be deleted as recommended in P-11-14. However, the grandfather clause can be significantly amended to restrict its usage. It is impractical to immediately pressure test all transmission pipelines that have not been pressure tested. AGA provided language in its previous comments to require pressure testing of certain grandfathered transmission pipelines. The comments submitted herein provide for additional safety enhancements.

It is also impractical to require that all in-service transmission pipelines have a post-construction pressure test of 1.25 times the MAOP. It appears that many people believe that mandatory testing is the requirement of NTSB safety recommendation P-11-15. A careful reading of the recommendation shows that the NTSB is not requiring a pressure test of 1.25 times the MAOP. Instead, the NTSB questions how the stability of defects is addressed. This is important because there are low stress transmission pipelines that have a pressure test below 1.25 times the MAOP. There may or may not be defects that have been eliminated by the hydrotest, but the remaining defects are unlikely to result in a rupture at low stress levels.

Hypothetically, a pipeline with an MAOP of 300 psig may have had a 1.20 times the MAOP (360 psig) pressure test in 1960. There are no engineering principles to support taking this pipeline out of service to re-hydrotest it an additional 0.05 times the MAOP (375 psig), which would be an additional 15 psig. The suggestions provided by AGA seek to avoid these types of adverse regulatory situations.

B. Low Stress Pipeline Alternatives to MAOP Testing

The suggested alternatives presented by AGA are based upon the fact that it is rare for a transmission pipeline operating below 30% SMYS to fail due to a manufacturing or construction defect, and if they do fail data has shown that low stress pipelines are much more prone to fail by leakage rather than rupture. Even if outside interactive forces cause the low stress pipeline to fail in the rupture mode, the PIR is small compared to larger diameter, higher MAOP pipelines. There are
preventive and mitigative measures that operators can implement to ensure that action is taken for the appropriate threat. The preventive and mitigative measures should be performance based rather than a prescriptive set of actions.

AGA has provided revisions to the AGA's Integrity Verification Process decision tree that it submitted with previous comments that shows the enhancements for pipeline segments operating at or below 30% SMYS (see Exhibit 1). AGA estimates that approximately 11,000 miles of gas utility pipelines are located in HCAs, and 6,400 miles are greater than 30% SMYS.

The following sections provide additional detail on the preventative and mitigate measures that should be taken on the four pipeline categories described earlier in these comments.

1. Threat of Susceptible Long Seam Failure

Transmission pipelines located in HCAs that operate above 30% SMYS with susceptible seam types and where the operator has a history of seam failure will need to have the pressure records reviewed to confirm that the pipeline segment has been subjected to a test pressure of 1.25 X MAOP or greater for a sufficient period of time to identify manufacturing and construction anomalies that could fail independently in operation.

The Baker Report commissioned by PHMSA states,

“[T]his report documents a review focused on evaluation of longitudinal seams on LF-ERW pipe and lap-welded pipe, particularly that manufactured before 1970, as well as DC-ERW pipe and EFW pipe. As part of the integrity management requirements for pipelines in high consequence areas, 49 CFR 195.452 (j) (6) states “for low frequency electric resistance welded pipe or lap-welded pipe susceptible to longitudinal seam failure, an operator must select integrity assessment methods capable of assessing seam integrity and of detecting corrosion and deformation anomalies.”

The report further states,

“Experience indicates that the number of time-dependent failures of lap-welded seams, if any, seems to be small. This review found only two types of seam breaks in lap-welded pipe; poorly fused seams and burned-metal defects. Where such defects have caused failures over pressurization was a known or suspected cause. The implication of the apparent lack of evidence of the occurrence of time-dependent failures associated with lap-welded pipe is that very few if any of these pipelines would be found susceptible to seam failure.”

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124 Integrity Management Program Delivery Order DTRSS6-02-D-70036 Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Department of Transportation Research and Special Programs Administration, Office of Pipeline Safety, October 2003
There is sufficient evidence that operators can identify whether transmission pipeline segments in their systems have shown a susceptibility to seam failure. These segments may have already been addressed with a post-construction pressure test or can be addressed through a one-time ILI inspection or Subpart J pressure test with subsequent reassessments under integrity management regulations (Subpart O).

2. Low Stress Pipelines Without Pressure Test Record

Transmission pipelines without pressure test records operating at or below 30% SMYS in an HCA must minimize the possibility of interactive threats. This can be accomplished by completing assessments for internal and external corrosion as well as confirming material records (in those instances where material records are incomplete) through non-destructive testing and coupon/cylinder testing if the pipeline is taken out of service. The probability of a rupture is very low, but operators must ensure that they verify the pipe material specification and use an integrity management process to confirm the integrity of the pipeline as required under Subpart O.

There are several technical studies in the public domain regarding the threshold between the failures of a natural gas pipeline by leakage versus by rupture. AGA and the Interstate Natural Gas Association of America are commissioning another independent study to better quantify the relative risks. A recent study titled, “Study of pipelines that ruptured while operating at a hoop stress below 30% SMYS,” by Rosenfeld and Fassett, examines 750 pipeline failures over several decades. Of those 750 failures only nine were found to be in gas services operating below 30% SMYS. Of those nine failures, three were caused by axial loading due to earth movement or external damage and one was due to previous mechanical damage on the pipeline. An additional four failures were found to have a primary cause of external or internal selective seam corrosion. This leaves only one failure of a pipeline operating at a hoop stress less than 30% SMYS in natural gas service to have a root cause due to manufacturing and construction defects. The incident was a 1937 Grade B, 10.77-inch pipe of low frequency - electric resistance welded construction.

3. Low Stress Pipelines That Have Already Been Pressure Tested

AGA suggests that transmission pipelines operating in HCAs and at or below 30% SMYS with a pressure test record need no additional MAOP testing or integrity management measures beyond those in Subpart O. The manufacturing and construction defects have been addressed. The operator needs to continue to take action to minimize the threat of excavation damage because of the extensive excavation that typically occurs in HCAs. As discussed earlier, it is not practical or cost-beneficial to remove transmission pipelines from service that have already been pressure
tested to re-test the pipelines for a small incremental pressure test. This is especially true with low stress transmission pipelines that are unlikely to fail by rupture. The best way to enhance safety is to focus on the potential interactive threats that could result in failure by rupture.

If an operator determines that excavation damage and outside force (e.g., earth movement, floods) are threats to the integrity of a covered segment, the operator must take measures to minimize the risks to the covered segment from the excavation damage or outside force threats. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

4. Pipelines with a Small Potential Impact Radius

AGA believes that pipelines that have a PIR of 200 feet or less require no MAOP testing or additional integrity management measures beyond those in existing regulation. The small diameter and low operating pressure would result in a relatively small area of consequence even if the pipe suffered a failure by rupture. The operator needs to continue to take action to minimize the threat of excavation damage due to the extensive excavation that typically occurs in HCAs. These suggestions are consistent with the way PHMSA has addressed potential incident scenarios in a practicable and cost beneficial manner.

PHMSA and operators have experience in prioritizing risks within HCAs.

The definition of HCAs for gas transmission pipelines was set forth in a final rule on August 6, 2002. The definition included Class 3 and 4 locations, and “identified sites”, i.e., buildings housing people who have limited mobility or are difficult to evacuate and outside areas where there is sufficient evidence of people congregating. The rule listed ways for an operator to identify these sites, including visible marking, licensure or registration by a Federal, State, or local agency, knowledge of public safety officials, or a list or map maintained by or available from a Federal, State, or local agency.125

The majority of LDC operators have been using the PIR method of determining HCAs. The HCA methodology is not just limited to scenarios that can impact 20 homes. The identified sites portion of the transmission integrity management program is a very complex regulatory system where operators must identify areas where people will congregate and provide additional risk mitigation measures.

RSPA/OPS expects that many, perhaps most, operators will follow the Potential Impact Circle option for defining HCAs. Under this approach, an operator would calculate

125 Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines); Final Rule, 68 Fed. Reg. 69795, 69784, December 15, 2003
the heat affected zones along its pipeline that would result from a pipeline rupture. An operator would determine the radius of the Potential Impact Circle for the pipeline, identify segments of pipeline within a Potential Impact Radius of “identified sites,” and identify segments of pipeline having 20 or more residences within a Potential Impact Circle. Such segments would be HCAs, and the length of pipeline included in the HCA would be the pipe within the HCA plus the length of pipe extending one Potential Impact Radius in both directions beyond the HCA.\textsuperscript{126}

AGA believes that its suggestions will align the PHMSA draft IVP with existing integrity management regulations designed to address integrity threats in class 3 and 4 areas that are not captured by HCAs.

For transmission pipelines operating at low pressures, like much of the pipeline operated by distribution companies, the radius of the Potential Impact Circle calculated with the C–FER model will be small. For example, the radius for a 6-inch diameter pipeline operating at 150 psi would be 50 feet. It is unlikely that 20 buildings intended for human occupancy could be found in circles of such small radius. It is also less likely that “identified sites” will be found within the circles as the radius decreases. As a result, using the Potential Impact Circle option will tend to exclude much low-pressure pipeline from the assessment requirements of this rule. Because accidents along these pipelines in developed areas can affect people and property, the rule requires an operator of a low-stress pipeline in these developed areas to take additional preventive and mitigative actions.\textsuperscript{127}

III. Conclusion

AGA commends PHMSA’s continuing commitment to pipeline safety and appreciates the opportunity to comment on the PHMSA draft IVP. Safety is AGA’s number one priority and commitment. AGA’s fourth set of comments focus specifically on low stress pipelines operating at or below 30% of the Specified Minimum Yield Strength (SMYS). AGA provides suggestions that can enhance the safety of these pipelines consistent with the Pipeline Safety Act of 2011, National Transportation Safety Board (NTSB) safety recommendations and studies of independent technical experts. The suggestions are based upon the fact that PHMSA and industry recognize the relatively low risk posed by these pipelines and the likelihood that failures will result in leakage rather than rupture.\textsuperscript{128} In the few instances where a low stress pipeline failed by rupture, the proximate causes were interactive threats such as long seam corrosion or latent third party damage from excavation. The Pipeline Safety Act of 2011 does not require MAOP verification testing for untested low stress transmission pipelines in HCAs (pipelines at or below 30% SMYS). In lieu of MAOP verification testing, AGA provides suggestions that create four categories of low stress transmission pipelines and includes safety enhancements and risk mitigation actions for each category.

\textsuperscript{126} Id. at 69785
\textsuperscript{127} Id. at 69785
\textsuperscript{128} Id. at 69795
If you need additional information please feel free to contact me.

Respectfully submitted,

Date: December 6, 2013

By: [Signature]

Christina Sames

For further information, please contact:

Christina Sames
Vice President
Operations and Engineering
American Gas Association
400 North Capitol Street, NW
Washington, D.C. 20001
(202) 824-7214
csames@aga.org

Philip Bennett
Senior Managing Counsel
American Gas Association
400 North Capitol Street, NW
Washington, D.C. 20001
(202) 824-7339
pbennett@aga.org
Technical Comments on the Social Cost of Methane As Used in the Regulatory Impact Analysis for the Proposed Emissions Standards for New and Modified Sources in the Oil and Natural Gas Sector

Prepared for:

American Council for Capital Formation

December 3, 2015
Authors*

Anne E. Smith, Ph.D.
Sugandha D. Tuladhar, Ph.D.
Scott J. Bloomberg

* The authors acknowledge the valuable research support provided by Dr. Mei Yuan.
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EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency (EPA) proposed emission standards for methane (CH4) and volatile organic compounds from new and modified sources in the oil and natural gas sector (referred to as “the Proposed Rule” in this report) on August 18, 2015. Accompanying this Proposed Rule is a Regulatory Impact Analysis (RIA) that is required under Executive Orders 12866 and 13563 for all major rulemakings from Executive Branch agencies. The RIA contains estimates of the net benefits of each of several options that the Proposed Rule is considering, which are equal to each option’s estimated benefits minus its estimated compliance costs.

Our comments address technical issues with the RIA’s monetized benefits estimates, which are entirely based on potential reductions in future climate change due to CH4 reductions, using a concept called the social cost of methane (SC-CH4). We demonstrate that EPA’s estimates of the benefits are: 1) highly uncertain and very likely overstated; and 2) lack the appropriate peer review that is necessary for use in supporting regulatory policy. We also explore the implications of these issues with the Proposed Rule’s net benefits estimates, and find they are far more likely to be negative than positive.

More specifically:

- We conclude that the RIA’s estimates of benefits from CH4 reductions using its SC-CH4 estimates are highly uncertain and likely overstated for multiple reasons:
  - The EPA’s SC-CH4 estimates are based upon a single study (Marten et al., 2014) whose estimates are significantly greater than, and inconsistent with, available estimates in other published papers (see Section II for a summary of the rest of the literature).
  - EPA relies on SC-CH4 estimates that reflect global benefits rather than domestic benefits, a practice that is contrary to the Office of Management and Budget’s (OMB’s) Circular A-4 (OMB, 2003) and inconsistent with the theoretical underpinnings of benefit-cost analysis that endow the method with its ability to guide a society towards policies that will improve its citizens’ well-being. Circular A-4 calls for use of domestic benefits, and notes that any estimates of non-domestic benefits should be presented separately. EPA’s use of global SC-CH4 benefits estimates (and failure to even present domestic benefits, which are readily obtained

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2 EPA, Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, EPA-452/R-15-002, August 2015.
3 Circular A-4 states “Your analysis should focus on benefits and costs that accrue to citizens and residents of the United States. Where you choose to evaluate a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately.” (OMB, 2003, p. 15).
from the same models) results in a significant overstatement of benefits and net benefits of the Proposed Rule.\textsuperscript{4}

- The RIA includes a 2.5% discount rate in its range of benefits, which is inconsistent with the short atmospheric lifespan of CH4. Its inclusion overstates the upper end of EPA's SC-CH4 estimates, and hence its net benefits.

- Marten et al. (2014) have used assumptions regarding indirect effects on radiative forcing from changes in tropospheric ozone and stratospheric water vapor levels that lack clear support from the scientific literature.\textsuperscript{5} This assumption, which is uncertain and not validated, could be a substantial source of overstatement in EPA's SC-CH4 estimates. For example, compared to a zero indirect effects assumption, it increases EPA's SC-CH4 estimate by about 36% (when using a 3% discount rate).

- EPA's SC-CH4 estimates are based on an average of five socioeconomic scenarios, four of which assume no incremental policies to reduce emissions in the future (also known as "business as usual" scenarios). Use of scenarios that assume no future emissions control policies to estimate the benefit of reducing a ton of emissions in the near-term overstates the SC-CH4 estimates.\textsuperscript{5}

- The absence of a full scientific peer review of the methodology behind EPA's SC-CH4 estimates calls into question the reliability of all of the RIA's estimated benefits and net benefits. We conclude more extensive peer review is especially warranted in this particular case for several reasons:

  - The integrated assessment models (IAMs) that were used to compute EPA's SC-CH4 estimates were modified in a significant manner that has not been reviewed by the original model developers.\textsuperscript{7} Other researchers working in this field have not had a chance to concur or disagree with the methodological changes and alternative input assumptions that EPA believes cause its SC-CH4 estimates to be so much greater than other published estimates.

  - The development of new SC-CH4 estimates by modifying pre-existing IAMs to make "standardized" calculations is inconsistent with the concept of using multiple existing

\textsuperscript{4} We are aware that this practice has also been used in the development of Federal social cost of carbon estimates by the Interagency Working Group (IWG), but the IWG decision does not reflect an agreed principle among economists, and we disagree with it for the reasons provided in these comments.

\textsuperscript{5} Radiative forcing is a measure of the influence a factor has in altering the balance of incoming and outgoing energy in the Earth-atmosphere system and is an index of the importance of the factor as a potential climate change mechanism (IPCC 2007). It is expressed in Watts per square meter (W/m\textsuperscript{2}).

\textsuperscript{6} We are aware that this use of business-as-usual scenarios also occurred in the development of Federal social cost of carbon estimates by the IWG, but the IWG method does not reflect an agreed principle among economists, and we disagree with it for reasons provided in these comments.

\textsuperscript{7} EPA's modifications to the models are discussed in Section IV.1.
models to identify the range of uncertainty in the best-available science-based estimates.\(^5\)

- EPA conducted an internal peer review process and the paper upon which it has relied (Marten et al. 2014) has been published in a peer-reviewed journal. However, those two types of reviews do not replace the need for a more rigorous independent scientific review in light of the types of changes described above. Additionally, EPA’s internal reviewers lacked consensus on the use of the paper’s SC-CH4 estimates for evaluation of major regulations.

To provide a quantitative assessment of the sensitivity of the RIA’s estimates of benefits and net benefits to the technical issues that we have identified, we have re-estimated the SC-CH4 values under several alternative assumptions that we consider more reasonable. These alternative calculations include 1) eliminating from consideration the 2.5% discount rate, 2) limiting benefits to a domestic geographic scope, 3) using alternative assumptions regarding the indirect effects on radiative forcing, and 4) eliminating “business as usual” emissions projections as the reference point for computing future damages from a ton of incremental emission that would occur today. EPA’s assumptions on these matters are discussed in Section III, along with our explanations for why our alternative assumptions are more reasonable for estimating SC-CH4 for use in a Federal RIA. All of our alternative SC-CH4 calculations have been made using the same IAMs that Marten et al. (2014) used to make their SC-CH4 estimates.

Figure 1 provides a summary of how the EPA’s SC-CH4 estimates would change based on assumptions we consider either more reasonable or subject to too much uncertainty for EPA to rely on a single point estimate. The first row shows the range of SC-CH4 included in the RIA based on mean values using 2.5%, 3.0%, and 5.0% discount rates.\(^6\) Each subsequent row includes a revised range based on different cases we constructed to address some of the technical issues we identified in EPA’s SC-CH4 estimates. Case A removes from consideration the 2.5% discount rate because it is not appropriate given that the shorter atmospheric lifespan of CH4 implies that the resulting climate benefits are not intergenerational. Cases B, C, and D then use a range of discount rates from 3% to 5%, while layering on additional alternative assumptions. Case B shows the range of SC-CH4 estimates when limited to a domestic geographic scope. Case C removes the assumption EPA made on a 40% enhancement of radiative forcing due to indirect atmospheric effects (in addition to the change for Case B). Case D incorporates the same changes as in Case C, but also ensures the baseline emissions projection provides

\(^5\) We are aware that standardization was also used, although to a lesser extent, in the development of Federal social cost of carbon estimates by the IWG; but the IWG decision does not reflect an agreed principle within the modeling profession, and we disagree with it for reasons provided in these comments.

\(^6\) We have not used the 95th percentile worst-case values in these ranges because the 95th percentile value would confuse uncertainty about climate impacts per se with uncertainty in estimating the impact of CH4 on climate change, which is the concern with EPA’s SC-CH4 estimates that our comments are highlighting.
consistency between future emissions control policies and the current emissions reduction effort that is implied if the SC-CH4 is to be used to make near-term emissions reduction decisions.\textsuperscript{10}

As Figure 1 shows, using all the alternative assumptions produces SC-CH4 estimates that are as much as 90% and 94% lower than EPA’s SC-CH4 estimates for 2020 and 2025, respectively.

**Figure 1. Alternative Estimates of SC-CH4 Reflecting Key Methodological Uncertainties**

<table>
<thead>
<tr>
<th>Case</th>
<th>Description</th>
<th>SC-CH4, $ per tonne of CH4 (2012$)</th>
<th>% Change Relative to RIA Range</th>
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</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Min</td>
<td>Max</td>
</tr>
<tr>
<td>RIA</td>
<td>RIA Option 2 (2.5%, 3.0%, and 5% discount rates)</td>
<td>587</td>
<td>1,721</td>
</tr>
<tr>
<td>A</td>
<td>RIA Option 2 (3.0%, and 5% discount rates)</td>
<td>587</td>
<td>1,309</td>
</tr>
<tr>
<td></td>
<td>0%</td>
<td>-24%</td>
<td>0%</td>
</tr>
<tr>
<td>B</td>
<td>Domestic (U.S.) specific SC-CH4 values averaged across all socioeconomic scenarios from PAGE and FUND models.</td>
<td>106</td>
<td>210</td>
</tr>
<tr>
<td></td>
<td>-82%</td>
<td>-88%</td>
<td>-81%</td>
</tr>
<tr>
<td>C</td>
<td>Domestic (U.S.) specific SC-CH4 values averaged across all socioeconomic scenarios from PAGE and FUND model without the indirect effects.</td>
<td>69</td>
<td>141</td>
</tr>
<tr>
<td></td>
<td>-88%</td>
<td>-92%</td>
<td>-88%</td>
</tr>
<tr>
<td>D</td>
<td>Domestic (U.S.) specific SC-CH4 values for the 5th Scenario from PAGE and FUND model without the indirect effects.</td>
<td>58</td>
<td>99</td>
</tr>
<tr>
<td></td>
<td>-90%</td>
<td>-94%</td>
<td>-90%</td>
</tr>
</tbody>
</table>

Note: The Min and Max values span different discount rates, EPA’s Low and High total costs, and climate benefits. For Cases B, C, and D, we do not report U.S.-specific SC-CH4 estimates from the DICE model because it is a global model and does not include regional details (see Section III.2 for discussion).

The percentage changes in the SC-CH4 estimates would directly translate to percentage changes in the overall estimated benefits since there is not any change associated with the assumed tons

\textsuperscript{10} To do this, Case D relies solely on estimates using one of five scenarios used by EPA, known as the “5th Scenario.” This eliminates the 80% weight that EPA has given to estimates using future emissions projections that assume no incremental reductions in greenhouse gas emissions in the future (i.e., the four other socioeconomic scenarios that EPA used that reflect “business as usual” policy). Section III.5 explains these scenario choices in more detail.
of CH4 reductions. Thus, we find that the Proposed Rule is likely to result in net costs, rather than net benefits as shown in Figure 2.

Figure 2. Range of Net Benefits and Costs in 2020 and 2025 (Millions of 2012$)

Figure 2 shows that even using EPA’s SC-CH4 estimates (labeled “RIA” in the two figures above), the Proposed Rule’s net benefits could be negative (or, in other words, the Proposed Rule could have net costs). Figure 2 also shows that when sequentially adjusting for each of the technical issues we have identified, the range of net benefits estimates becomes entirely negative—by more than negative $100 million per year even at the ranges’ upper bounds. This exceptional degree of sensitivity of the net benefits estimates to alternative reasonable assumptions and the lack of full scientific peer review of the science and approach used to estimate EPA’s SC-CH4 render it inappropriate to use EPA’s SC-CH4 estimates in making major national policy decisions. We also note that the downward impact on net benefits associated with each individual assumption that we have explored makes it unsupportable for EPA to suggest that the Proposed Rule will produce positive net benefits.

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11 Although it is not shown here when using a discount rate range of 3% to 5% and changing each of the assumptions associated with Cases B and C individually, net benefits remain negative over the entire range by at least -$33 million. When changing the assumption associated with Case D on its own, the net benefits range remains mostly negative (i.e., -$88 million to +$13 million in 2020 and -$204 million to +$55 million in 2025).
I. INTRODUCTION

On August 18, 2015, the U.S. Environmental Protection Agency (EPA) proposed emission standards for new and modified sources in the oil and natural gas sector (referred to as “the Proposed Rule” in this report) as part of the President’s Climate Action Plan. The Proposed Rule’s goal is to cut methane (CH4) emissions from the oil and gas sector by 40% to 45% from 2012 levels by 2025.12

Accompanying this Proposed Rule is a Regulatory Impact Analysis (RIA)12 that is required under Executive Orders 12866 and 13563 for all major rulemakings from Executive Branch agencies. The RIA contains estimates of the net benefits of each of several options that the Proposed Rule is considering, which are equal to each option’s estimated benefits minus its estimated compliance costs. Our comments address technical issues with the RIA’s benefits calculations, and their implications for the net benefits estimates. Although our comments do not address any aspect of the compliance cost estimates, that does not imply that we endorse those cost estimates.

The RIA’s benefits estimates are calculated by multiplying an estimate of the tons of methane reduction under the Proposed Rule by an estimate of the social cost of methane (SC-CH4). The SC-CH4 is the focus of our comments. It is an estimate of the dollar value of societal damages per ton of methane emission that would occur in a near-term year (such as 2020 or 2025). Although climate damages are attributed to a ton of near-term emission, they are based on projections of future climate outcomes many years into the future, and thus are also determined by future assumed levels of greenhouse gas emissions. These projections are made using one or more “integrated assessment models” (IAMs).

EPA’s SC-CH4 estimates are based on a paper by Marten et al. (2014). Given a number of technical issues we discuss below, we conclude that SC-CH4 estimates based solely on Marten et al. (2014) do not reflect the standards of scientific review and technical maturity that should be required before use in guiding major Federal regulatory decisions. We also conclude that EPA’s SC-CH4 estimates are likely overstated. As a result of sensitivity analyses we conduct on alternative assumptions for estimating the SC-CH4 values, we find a high likelihood that the Proposed Rule will result in negative net benefits, contrary to the RIA’s conclusions. For our quantitative sensitivity analyses, we focus on EPA’s Option 2, but the concerns we raise apply to all of the options in the RIA.14

The rest of the report is organized as follows. Section II provides a discussion of the approach EPA used to calculate the SC-CH4 estimates. Section III discusses the technical issues we have

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13 EPA, Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, EPA-452/R-15-002, August 2015.
14 EPA evaluates multiple options in the RIA, but is proposing to select Option 2 (RIA, p. 1-4).
identified with the SC-CH4 estimation approach and reasonable alternative assumptions. Section IV discusses the importance of a thorough peer review, and how the absence of such a process makes the EPA’s SC-CH4 estimates unreliable. Section V provides alternative estimates of the SC-CH4 when using reasonable assumptions. Finally, Section VI provides our conclusions based on the significant technical issues we identified in the SC-CH4 estimation approach and estimation of benefits. Appendix A contains additional summary tables and figures. Appendix B provides some additional commentary about the timing of SC-CH4 benefits and costs.
II. DESCRIPTION OF EPA’S CALCULATIONS OF BENEFITS, COSTS, AND NET BENEFITS IN THE RIA FOR THE PROPOSED RULE

EPA estimated the global social benefits of CH4 emissions reductions for the Proposed Rule using the SC-CH4 estimates from Marten et al. (2014), a metric that estimates the monetary value of global impacts associated with marginal changes in CH4 emissions in a given year in the relatively near future (e.g., in 2020 or 2025). The Marten et al. (2014) development of SC-CH4 estimates follows closely the work for computing the social cost of carbon (SCC) conducted by an interagency working group (IWG) that included EPA and other executive branch agencies and offices. The IWG used three existing IAMs to estimate the SCC for use in the Federal regulatory evaluation process. The estimates were released in 2010 and then subsequently updated in 2013 using updated data and model versions. The IWG, however, did not estimate any SC-CH4 values in 2010 or in 2013 while estimating SCC values. To value the benefits from this Proposed Rule, EPA worked on its own to develop the SC-CH4 estimates reported in Marten et al. (2014), without any apparent input or review from other participants in the SCC’s IWG.  

As with the SCC work, Marten et al. (2014) employed three IAMs to estimate the SC-CH4: 1) the Climate Framework for Uncertainty, Negotiation, and Distribution (FUND), 2) Dynamic Integrated Climate and Economy (DICE), and 3) the Policy Analysis of the Greenhouse Effect (PAGE). The SC-CH4 estimations used the same model version that was used by the EPA researchers for their most recent SCC work (DICE 2010, FUND version 3.9, and PAGE09 version 1.7 models).

For estimating the SC-CH4, these IAMs were run using the same set of baseline assumptions that the IWG SCC process used. A perturbation of one unit of CH4 was applied in a given year to estimate the changes in the climate damage. The SC-CH4 for the year of perturbation was then estimated by summing up the discounted marginal damages over the entire model horizon (i.e., through 2300) starting from the perturbation year.

Marten et al. (2014) ran the same five socioeconomic scenarios used by the IWG as part of the SCC process. These include fixed projections of gross domestic product (GDP), population, industrial CO2 emissions, and other greenhouse gas (GHG) emissions and radiative forcing projections based on a Stanford Energy Modeling Forum model comparison exercise (EMF-22).

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15 Marten et al. (2014) is a research paper written by five EPA staff and published in the Climate Policy journal.


17 In the DICE model, a 1 million tonne (Mt) increase in CH4 is assumed in a given “perturbation year.” In the PAGE model, an exogenous excess radiative forcing over time due to a 1 Mt increase in CH4 in a given “perturbation year” is assumed. The FUND model simulates an increase of 1 Mt of CH4 in each year for a decade is assumed. In all models, SC-CH4 estimates were computed as dollar per metric ton of CH4 for a year in question. Note that a tonne is a measure of a metric ton and is equivalent to about 1.10 short tons.
from 2009. Four of the five scenarios are Business as Usual (BaU) outlooks from four specific models selected by the IWG from among many models that participated in EMF-22 (*i.e.*, IMAGE, MiniCAM, MERGE, and MESSAGE). The fifth IWG scenario (called the “5th Scenario”) is based on the average of the 550 ppm CO\(_2\)-e stabilization scenario outlooks from the same four EMF-22 models. In addition, Marten *et al.* (2014) adopted the same equilibrium climate sensitivity distribution that the IWG used to model uncertainty associated with the climate sensitivity input to the IAMs.

To estimate the SC-CH4 for a given year, Marten *et al.* (2014) perturbed all three IAMs by an increment of CH4 emissions in that year.\(^\text{18}\) Marten *et al.* (2014) estimated the value of the SC-CH4 assuming a global geographic scope averaging the estimates across all 10,000 simulations,\(^\text{19}\) and also then averaging over each of the three IAMs for each of the five scenarios. This process was done using one of three constant discount rates (2.5%, 3%, or 5%) over a time horizon that extended through 2300, resulting in a mean SC-CH4 estimate for each of those discount rates. It is the uncertainty in those mean SC-CH4 estimates that is the focus of our comments.\(^\text{20}\) The year-specific SC-CH4 values used in the RIA (taken from Marten *et al.* 2014) are presented in Figure 3.

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\(^\text{18}\) See footnote 17 about perturbation details.

\(^\text{19}\) 10,000 simulations were done to capture the uncertainties in the underlying parameter values. In the DICE model, equilibrium climate sensitivity parameter values were selected probabilistically from the Roe-Baker distribution for each of the 10,000 runs. In the PAGE and FUND models, damage function parameters, equilibrium climate sensitivity parameter values, and other uncertainties were selected for each of the 10,000 runs.

\(^\text{20}\) Also following the IWG process, Marten *et al.* (2014) reported a SC-CH4 that was the average of the 95\(^\text{th}\) percentile worst-case values of the 15 IAM cases, using a 3% discount rate. This value is also reported in the RIA. In the quantitative examples in our comments, we focus only on the mean SC-CH4 values because our focus is on the uncertainties in obtaining a reliable estimate of the incremental climate damages of methane emissions. The 95\(^\text{th}\) percentile values reflect a completely different source of uncertainty, which is uncertainty in damages from climate change *per se.*
Figure 3. Social Cost of Methane, 2012-2050 (in 2012$ per tonne of CH4)
(Source: RIA, Table 4-3)

<table>
<thead>
<tr>
<th>Year</th>
<th>5 Percent Average</th>
<th>3 Percent Average</th>
<th>2.5 Percent Average</th>
<th>3 Percent 95th percentile</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>430</td>
<td>1,000</td>
<td>1,400</td>
<td>2,800</td>
</tr>
<tr>
<td>2015</td>
<td>490</td>
<td>1,100</td>
<td>1,500</td>
<td>3,000</td>
</tr>
<tr>
<td>2020</td>
<td>580</td>
<td>1,300</td>
<td>1,700</td>
<td>3,500</td>
</tr>
<tr>
<td>2025</td>
<td>700</td>
<td>1,500</td>
<td>1,900</td>
<td>4,000</td>
</tr>
<tr>
<td>2030</td>
<td>820</td>
<td>1,700</td>
<td>2,200</td>
<td>4,500</td>
</tr>
<tr>
<td>2035</td>
<td>970</td>
<td>1,900</td>
<td>2,500</td>
<td>5,300</td>
</tr>
<tr>
<td>2040</td>
<td>1,100</td>
<td>2,200</td>
<td>2,800</td>
<td>5,900</td>
</tr>
<tr>
<td>2045</td>
<td>1,300</td>
<td>2,500</td>
<td>3,000</td>
<td>6,600</td>
</tr>
<tr>
<td>2050</td>
<td>1,400</td>
<td>2,700</td>
<td>3,300</td>
<td>7,200</td>
</tr>
</tbody>
</table>

NERA obtained the code for all 3 IAMs and was able to run the IAMs for the different socioeconomic scenarios and discount rates, replicating the EPA’s SC-CH4 estimates. In doing this, of course, NERA also computed the 15 individual SC-CH4 estimates for each of the 3 IAMs and for each of the 5 socioeconomic scenarios that were averaged together to produce EPA’s SC-CH4 values. These 15 mean values, which are not available in any EPA document or in Marten et al. (2014), vary substantially around the mean values used in the RIA. Appendix A provides all of those underlying values for each discount rate for perturbation years 2020 and 2025. The analyses we describe in these comments are based on the results of the replication process and subsequent sensitivity analyses of the SC-CH4 values to several assumptions used in EPA’s estimation process that we consider inappropriate.

In the RIA, EPA reports net benefits based on ranges for total costs and total climate benefits (the range is based on low and high avoided CH4 emissions and discount rates). The low and high climate benefits in 2020 and 2025 are based on CH4 emissions reductions of 170,000 to 180,000 short tons and 340,000 to 400,000 short tons, respectively.\(^{21}\)

The RIA net benefits numbers are reproduced in Figure 4. The total monetized benefits are computed by multiplying CH4 emissions reductions by the applicable SC-CH4 estimate. For example, in the 2020 low case, a SC-CH4 of $1,300 per metric ton is multiplied by 158,000 metric tons of CH4 reductions (equivalent to EPA’s estimated reductions of a rounded 170,000 short tons) to produce $202 million of climate benefits. Although our comments do not address any aspect of the emission reduction estimates, that does not imply that we endorse those estimates.

\(^{21}\) RIA, Table 3-3.
Figure 4. RIA Total Costs, Total Monetized Benefits, and Net Benefits (Millions of 2012$)

<table>
<thead>
<tr>
<th>Discount Rate</th>
<th>2020 Low</th>
<th>2020 High</th>
<th>2025 Low</th>
<th>2025 High</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Costs</td>
<td>$150</td>
<td>$170</td>
<td>$320</td>
<td>$420</td>
</tr>
<tr>
<td>Total Monetized Benefits</td>
<td>$202</td>
<td>$214</td>
<td>$455</td>
<td>$547</td>
</tr>
<tr>
<td>Net Benefits</td>
<td>$52</td>
<td>$44</td>
<td>$145</td>
<td>$127</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Monetized Benefits</td>
<td>$91</td>
<td>$96</td>
<td>$216</td>
<td>$255</td>
</tr>
<tr>
<td>Net Benefits</td>
<td>-$59</td>
<td>-$74</td>
<td>-$104</td>
<td>-$165</td>
</tr>
</tbody>
</table>

EPA estimated the total compliance costs to industry to meet the requirements in the Proposed Rule. Although our comments do not address any aspect of the compliance cost estimates, that does not imply that we endorse them. EPA’s estimated annualized compliance costs reflecting annualized capital costs and ongoing O&M expenditures for Option 2 are $150 to $170 million in 2020 and $320 to $420 million in 2025.\textsuperscript{22} Subtracting the total costs from the total monetized benefits results in the estimated net benefits.

\textsuperscript{22} RIA, Table 6-2.
III. TECHNICAL ISSUES WITH ASSUMPTIONS USED IN THE SC-CH4 ESTIMATION PROCESS

EPA used SC-CH4 estimates that are based on assumptions that we do not consider the most reasonable. In each case, we find that EPA’s assumptions overstate the benefit estimates compared to assumptions that we consider more reasonable. We have identified five specific issues that are each discussed in this section. They are:

1. EPA adopted the SC-CH4 estimates from a single study and the SC-CH4 estimates are inconsistent with, and much greater than, those from other studies;

2. EPA should not provide benefits estimates that reflect only a global geographic scope, without even providing separate estimates for a U.S. geographic scope;

3. EPA’s use of SC-CH4 estimates based on a 2.5% discount rate is inconsistent with the short atmospheric lifespan of CH4;

4. EPA’s use of SC-CH4 estimates based on an assumption to increase radiative forcing due to indirect effects by 40% is not clearly supported by the scientific literature; and

5. EPA’s use of BaU emissions scenarios that reflect no incremental future mitigation policy creates an inappropriate overstatement of SC-CH4.

1. EPA Adopted the SC-CH4 Estimates from a Single Study and the SC-CH4 Estimates are Inconsistent with and Much Greater than Those from Other Studies

As described in Section II, EPA adopted the estimates of SC-CH4 from a single study (Marten et al. 2014). EPA researchers and others (Waldhoff et al. 2011, 2014) acknowledge that there are only a limited number of published estimates of the social cost of non-CO2 GHGs that have been estimated using IAMs, compared to a vast number of estimates of the SCC. The primary reason for the lack of non-CO2 social costs is that the research and knowledge base is very limited. Moreover, there are significant uncertainties associated with how to simulate CH4 and a lack of understanding of temperature and damage impacts. There appear to have been only 12 studies over the span of the past two decades (1993 to 2014) that quantified the impacts and costs of CH4 emissions reduction. They are listed in Figure 5.
### Figure 5. Summary of Literature on Estimates of SC-CH4 (1993-2015)
(The first 11 studies are referenced in Marten et al., 2014)

<table>
<thead>
<tr>
<th>S.No.</th>
<th>Study authors</th>
<th>Published year</th>
<th>IAM Model used</th>
<th>Scenario</th>
<th>Emissions year</th>
<th>SC-CH4 (2012$ / tonne of CH4)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Reilly and Richards</td>
<td>1993</td>
<td></td>
<td></td>
<td></td>
<td>*</td>
</tr>
<tr>
<td>2</td>
<td>Fankhauser</td>
<td>1994</td>
<td></td>
<td></td>
<td></td>
<td>*</td>
</tr>
<tr>
<td>3</td>
<td>Kandlikar</td>
<td>1995</td>
<td></td>
<td></td>
<td></td>
<td>*</td>
</tr>
<tr>
<td>4</td>
<td>Kandlikar</td>
<td>1995</td>
<td></td>
<td></td>
<td></td>
<td>*</td>
</tr>
<tr>
<td>5</td>
<td>Hammit et al.</td>
<td>1996</td>
<td></td>
<td></td>
<td></td>
<td>*</td>
</tr>
<tr>
<td>6</td>
<td>Tol</td>
<td>1999</td>
<td>FUND 1.6</td>
<td></td>
<td></td>
<td>*</td>
</tr>
<tr>
<td>7</td>
<td>Tol et al.</td>
<td>2003</td>
<td>FUND 1.7</td>
<td>2000</td>
<td>$484</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Hope</td>
<td>2005</td>
<td>PAGE95</td>
<td>2000</td>
<td>$176</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Hope</td>
<td>2006</td>
<td>PAGE2002</td>
<td>2000</td>
<td>$135</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Waldhoff et al.</td>
<td>2011</td>
<td>FUND 3.5</td>
<td>SRES A1B, A2, B1, B2</td>
<td>2010</td>
<td>$307</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>DICE2007 with MAGICC</td>
<td>EMF-22</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Marten and Newbold</td>
<td>2012</td>
<td>MAGICC</td>
<td>MiniCAM Base</td>
<td>2020</td>
<td>$877</td>
</tr>
<tr>
<td>12</td>
<td>Marten et al.</td>
<td>2014</td>
<td>DICE2010/FUND3.8/</td>
<td>EMF-22</td>
<td>2020</td>
<td>$1,309</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>PAGE09</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Waldhoff et al.</td>
<td>2014</td>
<td>FUND 3.9</td>
<td>SRES A1B, A2, B1, B2</td>
<td>2010</td>
<td>$469</td>
</tr>
</tbody>
</table>

* We do not report SC-CH4 estimates for these 1990s studies.

Within this limited literature, the initial papers published in the 1990s were largely focused on assessing the trade-offs in controlling different types of GHGs. These early papers also attempted to quantify the potency of non-CO2 GHGs relative to CO2 using a “global damage potential” metric. They did not use IAMs to directly simulate the damage per ton of each type of emission. From 1999 forward, IAMs became the tool of choice, offering estimates of social costs of non-CO2 GHGs using different models and baseline assumptions for different years. These studies produced estimates of social costs of methane that varied widely, as shown in the last column of Figure 5. Notably, Marten et al.’s estimates (which are the ones EPA has adopted for the Proposed Rule’s RIA) are much higher than all of the other available studies. One of the reasons that Marten et al. (2014) provided for its SC-CH4 estimates to be so much higher than prior studies’ was their use of more recent versions of the IAMs. However, since the publication of Marten et al. (2014), there has been an additional study that has estimated SC-CH4 (Waldhoff et al. 2014). Waldhoff et al. employed the latest version of the FUND model (version 3.9) and again produced estimates of SC-CH4 that were much lower than Marten et al. (2014). Their

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24 Except for Tol 1999.

25 FUND model version 3.9 assumes an exogenous SO2 radiative forcing. This is the only difference between FUND model version 3.9 and FUND model version 3.8 that was used in Marten et al. (2014).
2014 estimate is $469 per metric ton of CH4 (in 2012$); which is 64% lower than the estimate adopted by EPA of $1,309 per metric ton.26

Such variability in the literature, combined with the fact that EPA’s values are much higher than any of the other six estimates is a clear sign that the RIA may be overstating the Proposed Rule’s global benefits. It is also a reason why SC-CH4 methodology should be subjected to close scrutiny and reviewed by the original IAM developers, and that the assumptions that are found to cause its much higher estimates should be vetted by relevant scientists in a manner that is more thorough than the internally-controlled review that EPA conducted, or that a journal conducts prior to accepting a paper for publication. (The next section discusses peer review needs in more detail.)

2. EPA Should Not Provide Benefits Estimates That Reflect Only a Global Geographic Scope Without Even Providing Separate Estimates for a U.S. Geographic Scope

In the IWG’s SCC development, only global benefits values were presented. EPA has repeated the IWG’s global focus in its SC-CH4 estimates. Use of only global benefits instead of domestic (U.S.) benefits to compute climate benefits is inconsistent with almost all past practice in benefit-cost analyses. In justifying their use of global benefits for the SCC, the IWG argued:

...accounting for global benefits can encourage reciprocal action by other nations, leading ultimately to international cooperation that increases both global and U.S. net benefits relative to what could be achieved if each nation considered only its own domestic costs and benefits when determining its climate policies...the U.S. government can signal its leadership in this effort.27

This practice by the IWG (and adopted by EPA for the Proposed Rule) is contrary to the OMB’s Circular A-4 (OMB, 2003):

Your analysis should focus on benefits and costs that accrue to citizens and residents of the United States. Where you choose to evaluate a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately.28

By considering global benefits (and only global benefits), EPA is fostering a misunderstanding among RIA readers that implicitly overstates the benefits that the U.S. may expect from the Proposed Rule.

Gayer and Viscusi (2015) discuss the precedents for using non-U.S. benefits in evaluating U.S. regulations. They conclude that this practice is not only contrary to the requirements of

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26 Figure 17 in Appendix A shows different SC-CH4 values estimated by Waldhoff et al. (2014).
27 IWG 2015, page 32.
28 OMB 2003, p. 15.
Circular A-4, but that it is also inconsistent with past U.S. practice. They emphasize the role of legal standing in the determination of which benefits are appropriate to count, and note that legal standing of non-U.S. entities depends on reciprocity of effort in controlling emissions. Until there is more extensive global reciprocity in reducing GHGs to levels consistent with the estimated SC-CH4 in cost per ton, there is no precedent for considering only global benefits for U.S. regulatory policy evaluations.

Gayer and Viscusi provide a number of examples of how use of non-domestic benefits in the absence of reciprocity can cause a benefit-cost analysis to guide policy makers towards policy choices that are detrimental to domestic well-being. Without repeating the examples, we note that benefit-cost analysis is an analytic method designed to guide policy makers towards options that will improve the net welfare of their community. If conducted inconsistently with its original principles, the benefit-cost method loses its ability to inform policy makers whether their decisions will enhance the welfare of their constituents. One of those original principles is to account for the costs, preferences, and benefits of the residents of the political jurisdiction contemplating a policy (i.e., the U.S. in the case of the Proposed Rule). The reason that estimates of benefits should be limited to those within the domestic jurisdiction is that a policy that passes a benefit-cost test is presumed to be welfare-enhancing only because of a principle known as the potential compensation principle. For example, the distributional impacts of a policy may be so imbalanced that the policy would be detrimental to societal welfare; however, if the policy’s aggregate benefits across the domestic community do exceed its aggregate costs, the deciding policymaker has an ability to establish other (re redistributive) policies to spread the benefits or costs more fairly, and create a net welfare improvement. On the other hand, if the domestic benefits of a policy do not exceed its domestic costs, the potential for the deciding policymaker to effectuate the necessary redistribution does not exist. Thus, a policy that passes a benefit-cost test based on global benefits cannot be presumed to indicate a welfare-enhancing change unless it is also passes the benefit-cost test based solely on domestic benefits. This is the theoretical underpinning for the Circular A-4 requirement that policies report any estimates of non-domestic benefits separately from domestic benefits.

In conclusion, it is inappropriate for the RIA to use SC-CH4 values that reflect only global damages until there is global reciprocity in the control of GHG emissions. Although non-domestic benefits may merit some altruistic weight, such altruistic motives should be considered independently of the domestic balance of benefits and costs. We now turn to the question of what a domestic SC-CH4 estimate is, otherwise following the same assumptions and methodology as Marten et al. (2014).

In its 2010 report on the SCC, the IWG stated that it was not able to calculate domestic SCC estimates because it lacked details on the regional specifications in the model and because there

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29 The same arguments imply that use of global SCC values for U.S. regulatory policy evaluation is inappropriate.
is a dearth of country-specific social costs estimates in the literature (IWG, 2010).\textsuperscript{20} The IWG determined that it was only possible to include an “approximate, provisional, and highly speculative” range of 7% to 23% for the share of domestic benefits. However, we find that both the FUND and PAGE models directly compute and report U.S.-specific values for SCC and SC-CH4. EPA should have at least reported these domestic values for SC-CH4 in the RIA for the Proposed Rule.

We were able to generate the SC-CH4 global estimates from the PAGE and the FUND models running the exact same models as those used to compute EPA’s SC-CH4 estimates.\textsuperscript{31} Since the PAGE and the FUND model also contain U.S. and other regions, we were able to obtain the U.S.-specific SC-CH4 estimates directly from the same runs that produced the global estimates upon which EPA relied. These are shown in Figure 6 for a 3% discount rate (results for the 5% discount rate are in Figure 18 in Appendix A). The domestic SC-CH4 estimates are between 76% and 95% lower than the corresponding global estimates, depending on the socioeconomic scenario.

Using the PAGE model in 2020 (and using the 3% discount rate), the U.S.-specific SC-CH4 is on average about 78% less than the global SC-CH4; the FUND model U.S.-specific SC-CH4 on average is 94% less than the global SC-CH4. Therefore, the average SC-CH4 could be as small as $78 to $342 per tonne of CH4 compared to EPA’s $1309 per tonne of CH4 in 2020 using a 3% discount rate. These significantly lower domestic SC-CH4 estimates would result in significantly smaller climate benefits resulting in net costs for the Proposed Rule. These estimates, completely omitted from the RIA by EPA, demonstrate that EPA’s SC-CH4 estimates significantly overstate the potential domestic benefits from the Proposed Rule.

\textsuperscript{20} In its response to comments on the SCC, the IWG also noted that there is no bright line between global and domestic benefits because of potential spillover effects in international trade, national security, and public health (IWG 2015). This, however, does not mean that global benefits alone would produce a better understanding of net benefits than can be obtained through a separate evaluation of domestic and non-domestic benefits.

\textsuperscript{31} The DICE model is a global model and it does not include regional details. Hence we do not report U.S.-specific SC-CH4 estimates from this model.
### Figure 6. Summary of SC-CH4 Assuming Global versus Domestic Damages (Perturbation year=2020, discount rate=3%, (2012$ per tonne of CH4))

<table>
<thead>
<tr>
<th>IAM</th>
<th>Socioeconomic Scenario</th>
<th>RIA (Global)</th>
<th>Domestic (U.S.)</th>
<th>% Change Relative to RIA</th>
</tr>
</thead>
<tbody>
<tr>
<td>PAGE</td>
<td>IMAGE</td>
<td>$1,818</td>
<td>$353</td>
<td>-81%</td>
</tr>
<tr>
<td></td>
<td>MERGE</td>
<td>$1,383</td>
<td>$308</td>
<td>-78%</td>
</tr>
<tr>
<td></td>
<td>MESSAGE</td>
<td>$1,712</td>
<td>$411</td>
<td>-76%</td>
</tr>
<tr>
<td></td>
<td>MINICAM</td>
<td>$1,582</td>
<td>$380</td>
<td>-76%</td>
</tr>
<tr>
<td></td>
<td>STHSCN</td>
<td>$1,225</td>
<td>$257</td>
<td>-79%</td>
</tr>
<tr>
<td></td>
<td><strong>Average</strong></td>
<td><strong>$1,544</strong></td>
<td><strong>$342</strong></td>
<td><strong>-78%</strong></td>
</tr>
<tr>
<td>FUND</td>
<td>IMAGE</td>
<td>$1,507</td>
<td>$70</td>
<td>-95%</td>
</tr>
<tr>
<td></td>
<td>MERGE</td>
<td>$1,475</td>
<td>$89</td>
<td>-94%</td>
</tr>
<tr>
<td></td>
<td>MESSAGE</td>
<td>$1,374</td>
<td>$73</td>
<td>-95%</td>
</tr>
<tr>
<td></td>
<td>MINICAM</td>
<td>$1,458</td>
<td>$92</td>
<td>-94%</td>
</tr>
<tr>
<td></td>
<td>STHSCN</td>
<td>$1,059</td>
<td>$66</td>
<td>-94%</td>
</tr>
<tr>
<td></td>
<td><strong>Average</strong></td>
<td><strong>$1,375</strong></td>
<td><strong>$78</strong></td>
<td><strong>-94%</strong></td>
</tr>
</tbody>
</table>

3. **EPA’s Use of SC-CH4 Estimates Based on a 2.5% Discount Rate is Inconsistent With the Short Atmospheric Lifespan of Methane**

EPA’s SC-CH4 estimates are based on the same set of discount rates used in the IWG SCC analysis (2.5%, 3.0%, and 5.0%), even though CH4 has a much shorter lifespan than CO2. In its SCC work, IWG argued that a discount rate of 2.5% is based on the intergenerational impacts of CO2 due to its long lifespan in the atmosphere. Indeed, the IWG selected a 300-year time horizon because CO2 is presumed to have long-lived effect on climate. This very long atmospheric life does not apply to CH4. EPA’s rationale for adopting the SC-CH4 based on the same discount rates was that they wanted to rely on SC-CH4 estimates that were consistent with the SCC approach even though the gases have much different global warming potentials over time. Given that CH4’s atmospheric half-life of about 12 years is a small fraction of CO2’s half-life of over 100 years, climate impacts from CH4 do not have the same intergenerational equity and/or uncertainty about future growth that the IWG used to justify a 2.5% discount rate in its SCC deliberations.

Figure 7 shows the sensitivity of the SC-CH4 to the assumed discount rate for each of the three IAMs in 2020. Relative to the 3.0% discount rate, the SC-CH4 values using a 2.5% discount rate are about 27% to 37% higher depending upon the IAM; while the SC-CH4 values using a 5% discount rate are on average lower by 55% ($587 compared to $1,309 per tonne of CH4).

---

32 The atmospheric half-life of CH4 (i.e., its “e-folding lifetime” in precise technical terminology) is 12 years, while it is between 100 and 300 years for CO2 (Carbon Dioxide Information Analysis Center).
Figure 7. Summary of 2020 SC-CH4 by Socioeconomic Scenarios and IAMs
(Perturbation year=2020, 2012$ per tonne of CH4)

<table>
<thead>
<tr>
<th>IAM</th>
<th>Socioeconomic Scenario</th>
<th>Discount Rate</th>
<th>Percentage Change Relative to 3% Discount Rate Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>2.5%</td>
<td>3.0%</td>
</tr>
<tr>
<td>DICE</td>
<td>IMAGE</td>
<td>$1,559</td>
<td>$1,167</td>
</tr>
<tr>
<td></td>
<td>MERGE</td>
<td>$1,105</td>
<td>$855</td>
</tr>
<tr>
<td></td>
<td>MESSAGE</td>
<td>$1,411</td>
<td>$1,097</td>
</tr>
<tr>
<td></td>
<td>MiniCAM</td>
<td>$1,416</td>
<td>$1,041</td>
</tr>
<tr>
<td></td>
<td>5th Scenario</td>
<td>$1,154</td>
<td>$887</td>
</tr>
<tr>
<td>PAGE</td>
<td>IMAGE</td>
<td>$2,337</td>
<td>$1,817</td>
</tr>
<tr>
<td></td>
<td>MERGE</td>
<td>$1,782</td>
<td>$1,382</td>
</tr>
<tr>
<td></td>
<td>MESSAGE</td>
<td>$2,175</td>
<td>$1,712</td>
</tr>
<tr>
<td></td>
<td>MiniCAM</td>
<td>$2,069</td>
<td>$1,581</td>
</tr>
<tr>
<td></td>
<td>5th Scenario</td>
<td>$1,543</td>
<td>$1,224</td>
</tr>
<tr>
<td>FUND</td>
<td>IMAGE</td>
<td>$2,071</td>
<td>$1,507</td>
</tr>
<tr>
<td></td>
<td>MERGE</td>
<td>$1,971</td>
<td>$1,475</td>
</tr>
<tr>
<td></td>
<td>MESSAGE</td>
<td>$1,844</td>
<td>$1,374</td>
</tr>
<tr>
<td></td>
<td>MiniCAM</td>
<td>$1,965</td>
<td>$1,458</td>
</tr>
<tr>
<td></td>
<td>5th Scenario</td>
<td>$1,424</td>
<td>$1,059</td>
</tr>
<tr>
<td>Average</td>
<td></td>
<td>$1,722</td>
<td>$1,309</td>
</tr>
</tbody>
</table>

By including the 2.5% discount rate, the range of benefits from EPA’s SC-CH4 estimates extend much higher as shown in Figure 7. While discount rates of 3.0% to 5.0% are reflective of consumption rates of interest, there is little evidence for using 2.5% for the SC-CH4. We demonstrate the timing difference between CO2 and CH4 damage in our alternate approach later in these comments.

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33 Since the SC-CH4 is measured in consumption-equivalent units in the IAMs, the consumption rate of interest is an appropriate metric to obtain a present value of estimates of future damages. We note, however, that those damage estimates are to be compared to costs of control that are not accounted for endogenously in the IAMs used by the IWG (in the SCC work) and Marten et al. (2014) (in the SC-CH4 work). If the control costs were to be properly integrated into the IAMs, they would exert a consumption-reducing opportunity cost in future years, at a higher rate of interest than 3.0% to 5.0%. This effect would somewhat reduce the future consumption-equivalent damage estimates compared to what the IWG IAMs predict. This missing element of the IAM calculations would have an effect similar to using a slightly higher discount rate than the pure consumption rate of interest. Given the uncertainty on the true consumption rate of interest within a range as wide as 3.0% to 5.0% and the complexity of attempting to adjust for opportunity costs of spending, we do not consider it important to attempt to fine-tune the range of 3.0% to 5.0% for purposes of discounting IAM-based damage estimates, but only note that this omitted effect is a reason to give less weight to the lower end of the range of estimates of consumption rates of interest.
4. **EPA’s Use of SC-CH4 Estimates Based on an Assumption to Increase Radiative Forcing Due to Indirect Effects by 40% Is Not Clearly Supported by the Scientific Literature.**

Radiative forcing from CH4 released to the atmosphere can occur both directly and indirectly. The direct effects of CH4 on radiative forcing are characterized by a complex relationship that is a function of pre-industrial atmospheric concentrations of nitrous oxide and overlapping adsorption bands of CH4 and nitrous oxide (Marten et al. 2014). Potential indirect effects of CH4 are due to changes in tropospheric ozone which can enhance stratospheric water vapor levels. The indirect effect is accounted for in the three IAMs by assuming that it is equivalent to a fraction of the radiative forcing due to the direct effect. This assumption is uncertain and varies among analyses.

EPA’s SC-CH4 estimates are computed based on an assumption that their estimate of direct radiative forcing of CH4 will be increased by 40% in the DICE and the FUND models to get the total radiative forcing. One of the reviewers engaged by EPA noted that this particular assumption is “ad hoc.”

It is unclear from the model documentation how the indirect forcing effect of methane is applied in the PAGE model with respect to the calculation of SC-CH4 estimates. Since Marten et al. (2014) exogenously increased methane radiative forcing in PAGE using their DICE model’s radiative forcing outputs, possibly all the indirect effects assumed in DICE are already subsumed in the exogenous radiative forcing inputs to PAGE. However, because of the lack of clarity, we do not perform any sensitivity analysis for the PAGE SC-CH4 estimates.

To estimate the potential impact of this *ad hoc* assumption we re-ran the DICE and FUND models without the 40% multiplier, with resulting sensitivity estimates shown in Figure 8. We find that the impact of the indirect effects assumption is significant. As expected, lower radiative forcing results in smaller damages and hence lower SC-CH4 values. However, the magnitude of the effect depends upon the strength of the relationship between radiative forcing and temperature changes in each model. In 2020, for a 3% discount rate the average SC-CH4 from the DICE model is $1,009 per tonne of CH4. This value declines to $731 per tonne CH4 if the *ad hoc* assumption of 40% indirect effects on radiative forcing is removed. Across all socioeconomic scenarios in the DICE model, SC-CH4 values are reduced by 29% if indirect effects are removed. In the FUND model, the percentage reduction is even larger. However,

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34 Radiative forcing is a measure of the influence a factor has in altering the balance of incoming and outgoing energy in the Earth-atmosphere system and is an index of the importance of the factor as a potential climate change mechanism (IPCC 2007). It is expressed in Watts per square meter (W/m²).

35 However, Marten et al.’s application of the enhancement effect of 40% is not consistently applied between the DICE and the FUND model. In the DICE model, 40% is applied to the total global radiative forcing expression, while in the FUND model it is only applied to the first term of the global radiative forcing equation 2 in Marten et al. (2014). The FUND model introduced a parameter that can take on any value to increase the radiative forcing in FUND 3.8 (same version as used to compute the EPA’s SC-CH4 estimates).

since the FUND model has higher SC-CH4 estimates than the DICE model, the resulting 2020 average SC-CH4 from FUND is $789 per tonne of CH4.

**Figure 8. Summary of 2020 SC-CH4 Assuming No Indirect Effects on Global Radiative Forcing**

(Perturbation year=2020, discount rate=3%, 2012$ per tonne of CH4)

<table>
<thead>
<tr>
<th>IAM</th>
<th>Socioeconomic Scenario</th>
<th>RIA With Indirect Effects</th>
<th>Without Indirect Effects</th>
<th>% Change Relative to RIA</th>
</tr>
</thead>
<tbody>
<tr>
<td>DICE</td>
<td>IMAGE</td>
<td>$1,167</td>
<td>$834</td>
<td>-29%</td>
</tr>
<tr>
<td></td>
<td>MERGE</td>
<td>$855</td>
<td>$611</td>
<td>-29%</td>
</tr>
<tr>
<td></td>
<td>MESSAGE</td>
<td>$1,097</td>
<td>$783</td>
<td>-29%</td>
</tr>
<tr>
<td></td>
<td>MINICAM</td>
<td>$1,041</td>
<td>$744</td>
<td>-29%</td>
</tr>
<tr>
<td></td>
<td>5THSCN</td>
<td>$887</td>
<td>$634</td>
<td>-29%</td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>$1,009</td>
<td>$721</td>
<td>-29%</td>
</tr>
<tr>
<td>FUND</td>
<td>IMAGE</td>
<td>$1,507</td>
<td>$942</td>
<td>-38%</td>
</tr>
<tr>
<td></td>
<td>MERGE</td>
<td>$1,475</td>
<td>$855</td>
<td>-42%</td>
</tr>
<tr>
<td></td>
<td>MESSAGE</td>
<td>$1,374</td>
<td>$773</td>
<td>-44%</td>
</tr>
<tr>
<td></td>
<td>MINICAM</td>
<td>$1,458</td>
<td>$910</td>
<td>-38%</td>
</tr>
<tr>
<td></td>
<td>5THSCN</td>
<td>$1,059</td>
<td>$581</td>
<td>-45%</td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>$1,375</td>
<td>$798</td>
<td>-42%</td>
</tr>
</tbody>
</table>

5. **EPA’s Use of BaU Emissions Scenarios that Reflect No Incremental Future Mitigation Policy Creates an Inappropriate Overstatement of SC-CH4**

Following the IWG’s approach for its SCC estimates, EPA relied on SC-CH4 estimates that were calculated using a simple average of four BaU scenarios (IMAGE, MERGE, MESSAGE, and MiniCAM) that have growing GHG emissions and one scenario (5th Scenario) that reflects emissions from a substantial global GHG emissions reduction policy. All five socioeconomic scenarios treat emissions as exogenously specified, but the 5th Scenario is the only one of the five scenarios that reflects a consistent policy to price GHG emissions, not just in the near term, but through the entire model horizon. The choice of socioeconomic scenario is important for the social cost computation because the scenario’s assumptions regarding far-future emissions levels determine the amount of damage that the IAMs will attribute to a one-ton perturbation now. Damage curves are convex, meaning that at low levels of concentration, emissions pose little or no harm to the society, but as concentration increases, damage from emissions increases at an increasing rate. Thus, the higher the assumed future emissions, the higher the damage that ends up being assigned to a ton of emission today. The appropriate socioeconomic scenario to assume about future emissions levels is therefore an important issue, particularly in a case such as this where the analysis treats the emissions from those scenarios as exogenously fixed.

The only appropriate assumption for assigning a price on GHG emissions in the near term is that such pricing will continue to be in place (and gradually increased) into the future. It is illogical,
and indeed socially irrational, to choose to price emissions (i.e., to justify reducing them) in the current period based on an assumption that after the current period they will never again be priced (or reduced). However, that is exactly what is being done when exogenously-fixed BaU emissions projections are used to assess the benefit of one ton less of emissions in a year such as 2020 or 2025. The effect of this illogical assumption is to increase the SC-CH4 estimate compared to a more consistent assumption that the current period’s reductions are the first step on the path of a long-term global GHG emissions reduction policy. That is, it inappropriately increases the SC-CH4, resulting in an overstatement compared to more reasonable assumptions.

The use of five socioeconomic scenarios, four of which assume BaU emissions trajectories and only one of which assumes any reductions in future GHG emissions, effectively is then estimating the SC-CH4 with an 80% probability of no future emissions reductions and a 20% probability of emissions reductions to achieve 550 ppm. The 5th Scenario is the only scenario among the socioeconomic scenarios used to compute EPA’s SC-CH4 estimates that fits with the IWG’s belief that other countries will take reciprocal actions to reduce GHG emissions. The 5th Scenario is not necessarily the best or only appropriate emissions projection to use, but it is certainly closer than any of the four BaU scenarios upon which EPA relied. As one can see from Figure 9, the 5th Scenario produces a much lower SC-CH4 (roughly 20% lower across models and years) than the four BaU cases (as one would expect).

We conclude that, as long as one’s scenario options are limited to those already developed and adopted by the IWG (for the SCC work) and EPA (for the SC-CH4 work), only the 5th Scenario should be used to derive SC-CH4 estimates for use in Federal policy evaluations. In a more ideal situation, multiple different projections of emissions under reciprocal, globally-shared GHG reduction policies could be used to assess a range in the SC-CH4 values. However, we can be sure (given the convexity of IAM damage functions) that even the highest value within such a range would be lower than those produced giving 80% weight to the other four of the IWG scenarios.

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37 We note that the DICE model that Professor Nordhaus created and uses does not treat emissions and other socioeconomic variables as an exogenous input. Rather, it selects a SCC for a ton of emission today that accounts for an endogenously optimized path of future prices and associated emissions reductions. Thus, the true DICE model always produces SCC estimates for near-term emissions that are based on an internally-consistent assumption that pricing will continue into the future. EPA’s SC-CH4 values (and the IWG’s Federal SCC values) are purported to have been calculated using this DICE model, but are actually based on a model created by altering DICE so that it can no longer endogenously determine future emissions. In making this new “DICE-based” model, the internal consistency was no longer assured, and use of it with BaU emissions assumptions ensures its social cost results will lack that internal consistency.

38 This same concern applies to the IWG’s use of BaU scenarios to estimate a Federal SCC value.

39 The same conclusion holds for estimating Federal SCC values.
Figure 9. Summary of SC-CH4 for the Four BaUs and the 5th Scenario for 3% and 5% Discount Rates
(2012$ per tonne of CH4)

<table>
<thead>
<tr>
<th>Model</th>
<th>3.0%</th>
<th>5.0%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2020</td>
<td>2025</td>
</tr>
<tr>
<td></td>
<td>DICE</td>
<td>PAGE</td>
</tr>
<tr>
<td>BaUs</td>
<td>$1,040</td>
<td>$1,523</td>
</tr>
<tr>
<td>5th Scenario</td>
<td>$887</td>
<td>$1,225</td>
</tr>
<tr>
<td>Average</td>
<td>$1,009</td>
<td>$1,544</td>
</tr>
</tbody>
</table>

Conclusions

Compared to the SCC estimates in the literature, the literature on SC-CH4 estimates is very limited (as seen from Figure 5). Also, the climate science behind the social costs of non-CO2 GHG values in general, and CH4 in particular, is even more at an early stage than that for radiative effects of atmospheric CO2. Given the poor quality data for non-CO2 GHGs, the current IAMs make heroic assumptions, which imply lower quality, more uncertain estimates of SC-CH4 than SCC. Current estimates of SC-CH4, including EPA’s SC-CH4 estimates, should at best be viewed as the results of “what-if” analytical exercises, and should be interpreted with great caution when applying them to any actual regulatory evaluation.

In addition to the inherently low reliability of any SC-CH4 estimates, we have identified a number of questionable assumptions that determine the EPA’s SC-CH4 estimates. These include use of only global benefits (with no separation of domestic from non-domestic benefits), inclusion of a discount rate that is inconsistent with the shorter lifespan of CH4, an ad hoc assumption regarding the radiative forcing from indirect effects of CH4, and estimates that are heavily weighted by four socioeconomic scenarios that are inconsistent with the IWG’s belief that U.S. actions will lead to reciprocal actions from other countries to reduce GHG emissions. It is for these reasons that it is too premature and inappropriate to apply SC-CH4 estimates as part of the regulatory decision-making process. At a minimum, if any SC-CH4 estimates are to be used in the Proposed Rule’s RIA, they should be centered on the much lower quantitative estimates that we derive using a more reasonable set of IAM input assumptions and outputs (see Section V).
IV. EPA’S ESTIMATES LACK THE APPROPRIATE PEER REVIEW FOR USE IN SUPPORTING REGULATORY POLICY

Given the degree of sensitivity to alternative reasonable input assumptions identified in Section III, it is apparent that the approach that EPA has adopted is deficient and requires substantial peer review before the SC-CH4 estimates can be considered ready for use in policy decision making. An independent scientific peer review would have likely identified many of the same technical issues we have discussed. Indeed, some of the issues were identified in EPA’s internal peer review process, but appear to have been glossed over.

Below, we discuss three specific issues regarding the lack of an appropriate peer review of EPA’s methodology, approach, and estimates. These are:

1. EPA’s SC-CH4 estimates are based on significant modifications of the IAMs and render moot any previous peer reviews of those models;

2. EPA’s SC-CH4 estimates are based on harmonization of inputs across the IAMs that is not reflective of best available science; and

3. EPA’s peer review process of the SC-CH4 estimates was insufficient.

1. EPA’s SC-CH4 Estimates are Based on Significant Modifications of the IAMs and Render Moot any Previous Peer Reviews of Those Models

The IAMs used have frequently been cited in the peer-reviewed literature for estimating a global SCC (but not for a SC-CH4) and were used in the most recent Intergovernmental Panel on Climate Change (IPCC) assessment. A 2010 report of the National Academies of Science (NAS) identified these models as “the most widely used impact assessment models” (IWG 2015). The original authors have put in decades of research to incorporate the best available science through the course of these professional exchanges. However, EPA’s SC-CH4 estimates are based on an approach that has simplified and modified the IAMs, disregarding the original model developers’ scientific efforts; in the process, the models used to derive EPA’s SC-CH4 are no longer the well-documented and peer-reviewed models, even though EPA is attempting to represent them as such.

The FUND model is an IAM with a simplified representation of economic growth, the energy-use carbon cycle, and climate (Waldhoff et al. 2014). Based on EPA’s SC-CH4 documentation (Marten et al. 2014), the core structure of the FUND model was not modified because it could compute the social cost of the non-CO2 GHG gases directly by perturbing the emissions in any future year. The same, however, cannot be said for the other two models that were used to compute EPA’s SC-CH4 estimates.

The original DICE model was modified by incorporating the structural equations, but not the developer’s structural framework. As one of the most widely-used IAMs, DICE (using its full
structural framework) is a policy optimization model that computes an ideal best-response from an economically-efficiently viewpoint. The modification of the DICE model (even for the SCC estimation) resulted in a static or a descriptive model that lacks optimization and behavioral response, which is better described as “DICE-based.” There is no documentation as to why the DICE model was simplified from an optimization model to a simulation model or how this change might affect the structural integrity of the original DICE model and the resulting social cost estimates. In addition, the DICE model was also modified to include a representation of the atmospheric concentration of CH4 based on assumed emissions paths (Marten et al. 2014). Given the fundamental change in the model framework and inclusion of a simplified gas cycle model, the “DICE-based” model used to compute the EPA’s SC-CH4 estimates significantly deviates from the peer-reviewed original DICE model that Professor Nordhaus created and uses. Thus, results from this model should not be accorded the same status of reliability as those that come from the original DICE model.

The PAGE model was also modified by Marten et al. (2014) for the SC-CH4 estimation by replacing its pre-existing built-in CH4 mechanisms with a simpler set of exogenously-specified changes in radiative forcing. Similar to the FUND model, the original PAGE model contains a complex structure with uncertainties in many variables, including the radiative forcing from non-CO2 emissions. Marten et al. (2014) replaced the PAGE model’s endogenous methane-cycle logic with the exogenously-determined radiative forcing changes that they computed using their modified version of the DICE model. By doing this, the changes in the radiative forcing due to an emission impulse in a given year were harmonized for the DICE and the PAGE models. Beyond desiring consistency with the DICE model, there is neither justification in the model documentation as to why the PAGE model was changed nor any explanation of how this modification affected the original model’s SC-CH4 estimates. Further, because the PAGE model’s excess forcing over time is tied to the DICE model’s radiative forcing, any errors that may exist in the DICE modifications would extend into their PAGE modeling, and may also be compounded by any inconsistencies with the rest of PAGE’s pre-existing logic. Thus, as with the DICE model, the version of the PAGE model upon which EPA has relied for its SC-CH4 estimates can no longer be characterized as a peer-reviewed model.

To further demonstrate that the changes made to the IAMs for the EPA’s SC-CH4 estimates make any previous peer reviews moot, we note that such changes were made without a complete understanding of how the IAMs function. Our review of comments made directly by the developers of the EPA’s SC-CH4 estimates demonstrates limited exploration of the model responses. For example, the PAGE model has varying time intervals. In the near term, it makes

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41 As noted in the previous section, one (perhaps unintended) error that has occurred when using the modified version of DICE (adopted for computing EPA’s SC-CH4 estimates) is that it has been run using an exogenously-fixed emissions projection that is internally inconsistent with the concept of setting a price to reflect GHG emissions’ externalities. As described in that section, this has resulted in inappropriately-overstated estimates of both SC-CH4 and SCC that could not have been accidentally produced by the original version of DICE.
its computations on a decadal basis, while in the long term it makes its computations on a century basis. With reference to the implication of changing the model time steps in the PAGE model, the authors of the EPA’s SC-CH₄ estimates noted, “It is not clear if the result would hold if the size of the time steps in the model were reduced.”

Another point that demonstrates limited exploration of the nuances of model responses when computing EPA’s SC-CH₄ estimates is the observed inconsistent patterns of the underlying temperature changes. The pattern of projected temperature impacts in the DICE and PAGE models is distinctly different from that of the FUND model. Neither Marten et al. (2014) nor the RIA provide any discussion or justification for this difference.

In the DICE and PAGE models, temperatures rise quickly and then fall rapidly within this century as a result of a near-term increment in CH₄ emissions. For example, in the year of the impulse, the temperature change projected in the DICE and PAGE models is about 80% to 90% of the maximum temperature change. Figure 10 shows that the maximum temperature change occurs within a decade in the DICE model (blue markers) and the PAGE model (orange markers), and then declines to about 10% of the maximum temperature change by 2130. For the FUND model (green markers), the temperature change rises slowly reaching a maximum point by 2050. Decreases in the temperature change in the FUND model are much slower and sustained over a significantly longer time period. Even by the end of the model horizon (year 2300), temperature change in the FUND model maintains 15% of the maximum temperature change, while for the other two models it is only about 2% of the respective model’s maximum temperature change by 2300.

To evaluate this inconsistency further, we ran the same models used to compute EPA’s SC-CH₄ estimates and compared the temperature changes associated with a pulse of CH₄ and CO₂ emissions. Figure 11 shows the temperature changes associated with a pulse of CH₄ and CO₂ emissions in 2020 for the DICE and FUND models (the blue and green lines, respectively).

42 Marten et al. (2014).

43 Note that the temperature change in degrees C is different between the three IAM models.

44 We do not include the PAGE response given that the temperate response is similar to the DICE model and the PAGE model was not run for carbon impulse for this study.
Figure 10. Normalized Temperature Change for CH4 for the 5th Scenario
(Max=100%, Perturbation year=2020, ECS=3)

Figure 11. Normalized Temperature Change for CH4 and CO2 for the 5th Scenario
(Max=100%, Perturbation year=2020, ECS=3)
For these two scenarios, the temperature change for a CO\textsubscript{2} impulse stays higher than the CH\textsubscript{4} impulse temperature change response, as one would expect given the longer lifespan of CO\textsubscript{2} compared to CH\textsubscript{4}. The FUND model pattern is inconsistent with the short lifespan of CH\textsubscript{4} and overestimates temperature change compared to the DICE and PAGE models.\textsuperscript{45} This suggests that the EPA has not investigated the models properly to sufficiently understand the projected responses. These differences could not have been flagged by any of EPA’s selected peer reviewers, or by any journal article reviewers, because this information was never presented to those reviewers. NERA identified these patterns in its own independent replication exercises, and although we cannot explain them, they highlight again the need for a much more thorough peer review process of the modified IAMs before they can be considered mature enough for use in evaluation of major Federal regulations.

2. EPA’s SC-CH4 Estimates are Based on Harmonization of Inputs Across the IAMs that Is Not Reflective of Best Available Science

The objective of a model comparison exercise is to understand the different responses based on different model constructs. In any model comparison exercise, caution should be used to avoid harmonization of inputs between the models that would force fundamental features of a model to be eliminated. When efforts to standardize assumptions between models become excessive, they could produce results that are more similar than what they should be, overshadowing the insights about modeling uncertainty that can be derived from the original heterogeneity in individual models, reflecting the independent views and alternative approaches of their developers.

A well-established model comparison platform is the Energy Modeling Forum (EMF) that was established in 1976 at Stanford University. The EMF’s goal is to improve the use and usefulness of energy models by testing and understanding the differences between model estimates, while allowing models to operate independently. Models are and will be different, where an input in one model may be an output of other models (Sweeney and Weyant, 1979). Contrary to the approach adopted in computing EPA’s SC-CH4 estimates, EMF has always provided for model independence and cautions against over harmonization of input assumptions. This is reflected in the following quote from the Study Design guidelines for EMF-14, which was a forum specifically focused on climate change IAMs:

\textit{As in all EMF studies, the standardization of input assumptions is accomplished so that important inputs take on common values for each EMF scenario. This process facilitates the interpretation of the model comparison, allowing one to separate the dependence of key model results on model structure and on specific numerical inputs. However, in instances where a particular model includes an endogenous computation of an input selected for standardization, the modeler is urged to pursue the internal calculation in lieu of the EMF 14 input assumption.}

\textsuperscript{45} Such an overstatement of the temperature change would result in higher climate damages for a longer time period, which would therefore overstate the SC-CH4 from the FUND model.
By design this situation arises infrequently, but it is important for the modelers to maintain this flexibility.\textsuperscript{46}

The statements from EMF suggest that while input harmonization allows for a better understanding of how results are related to a model’s structure, it does not require changing the structural integrity of the model. The approach adopted to estimate EPA’s SC-CH4 estimates ignored this best practice in light of their changes to the DICE and PAGE model structures described above. Clearly, such model modifications cannot be justified as a standard procedure in model inter-comparison exercises, as it is inconsistent with the guidelines of the premier model inter-comparison forum, EMF. Further, in estimating a Federal SCC or a SC-CH4, the purpose of using three different IAMs was not to conduct an academic exercise in model inter-comparison—it was to reflect current scientific uncertainties by letting three generally-independent models produce their own results. Standardization was not necessary—and probably detrimental—to that goal of characterizing modeling uncertainty. Nevertheless, the fact that EPA made several significant changes to IAMs before using them implies a need for an in-depth review that has not yet been conducted.

3. EPA’s Peer Review Process of the SC-CH4 Estimates was Insufficient

EPA relied upon estimates of SC-CH4 from a single research paper, Marten \textit{et al.} (2014), which was written by EPA staff. Although there have been some reviews of the paper that are summarized below, we conclude that the significant modifications (and the absence of scientific justifications for some of the modifications) associated with that paper, combined with the fact that it reports SC-CH4 estimates so much higher than the rest of the literature, demands that a more thorough and independent scientific peer review process should be conducted before its results should be used as the sole determinants of an RIA’s benefits estimates.

We note that Marten \textit{et al.} (2014) has been published in a peer-reviewed journal, but we also note that such reviews do not address issues of concern for use in policy deliberations. The focus of peer reviews for journal publication is primarily to determine whether the paper makes a contribution to a particular body of knowledge. Publication peer reviews are not to evaluate or opine on the relevance of the contents of a paper for use in setting public policy. Further, publication of an article in a journal does not necessarily mean that the methodology or the approach laid out in the paper is the best or only approach. It is therefore incorrect to assume that the publication of the paper in an academic journal is an endorsement of the approach used to compute EPA’s SC-CH4 estimates, which reflects only one of several published estimates based on a science that is still uncertain and developing. The fact that its estimate is an outlier within the limited available literature suggests even greater concern with such an inference, albeit not a reason to block publication in a journal.

\textsuperscript{46} EMF, 1995, p. 1 (emphasis in original document).
Appearing to recognize that publication review is not sufficient for the use EPA has put this to in its RIA, EPA conducted its own internally-managed review (US EPA 2014). In this review, three EPA-selected experts responded in writing to a set of EPA-specified charge questions. Two charge questions (Question-1 and Question-7) were directly related to the application of the SC-CH4 which was the main concern of the internal review.\textsuperscript{47} EPA states that in light of the “favorable peer review,” EPA proposed to use the Marten \textit{et al.} (2014) SC-CH4 estimates to value CH4 reductions in the Proposed Rule.\textsuperscript{48} However, we have read the reviewers comments and we find that they did not provide a consensus view as stated in the Proposed Rule’s RIA, as we discuss below:

- Reviewer-1 points out that an application of the direct approach is theoretically better than the Global Warming Potential (GWP) approach and points to the differences between these two approaches when applied to computing CH4 benefits.\textsuperscript{49} However, this reviewer cautions in her response, “There, of course, is a host of issues that arises applying any social cost measure to regulatory analyses.” In response to Charge Question-7, Reviewer-1 does not offer any definite affirmative or a negative response, but makes a point that EPA should be forthcoming about the shortcomings of the social cost estimates.

- Reviewer-2, in response to charge Question-1, also does not say that it is appropriate for use in benefit-cost analysis of regulatory actions. He only affirms EPA’s view that the Marten \textit{et al.} (2014) approach is designed to measure the monetized value of an incremental change in CH4 emission. This reviewer cautions that the estimate of the effect of an addition of CH4 is a simplification of complex atmospheric chemistry. The reviewer referred to the increase in the radiative forcing due to the indirect effects of tropospheric ozone effects and stratospheric water vapor effects as an “\textit{ad hoc} assumption.” With regard to Charge Question-7, this reviewer also does not provide an explicit response that endorses such use of the SC-CH4 estimates. The reviewer only acknowledges that Marten \textit{et al.} (2014) consistently applied the IWG’s SCC concept to estimating SC-CH4. However, he does not validate the implementation of the models with modifications.

\textsuperscript{47} Question-1: Has EPA correctly interpreted the SC-CH4 estimates provided in Marten \textit{et al.} (2014) as designed to measure the monetized value of the climate impacts from marginal changes in CH4 emissions in a way that is appropriate for use in benefit-cost analysis of regulatory actions projected to change CH4 emissions. Question-7: Are there implementation issues not addressed in the paper that EPA should consider before applying the Marten \textit{et al.} estimates in regulatory analysis?

\textsuperscript{48} RIA, p. 4-15.

\textsuperscript{49} The Global Warming Potential (GWP) metric indicates the potential of a gas to absorb heat relative to CO2 over a particular period of time, usually 100 years. The GWP approach translates non-CO2 emissions to ‘CO2 equivalents’ (CO2eq) using estimates of the GWP for the non-CO2 gas and then multiplied by the SCC (Marten \textit{et al.} 2014).
Reviewer-3 also agrees with the other reviewers that the direct approach used by Marten et al. (2014) (as contrasted to the GWP approach) can be used to monetize the value of an incremental change in CH4. However, his review is the most critical and expresses concerns about moving forward with the direct non-CO2 GHG social cost estimates based on the IWG’s SCC methodology before having a peer-reviewed SCC methodology. This reviewer echoes the sentiments of many others (Pizer et al. 2015 and others cited in Marten et al. 2014) that have commented on the need for the greater scientific community to formally review the SCC and SC-CH4 approaches. Reviewer-3 is concerned that there are computational issues with calculating the SC-CH4 estimates and implementation issues using the SC-CH4 estimates for regulatory analysis.

The above comments hardly amount to endorsement for use of the EPA SC-CH4 estimates in regulatory impact analyses. Additionally, we note that EPA’s review did not address an even more fundamental question of, “What is the scientific basis for using the SC-CH4 estimates?” Ultimately, EPA’s justification to use its own SC-CH4 estimates from a single research paper is based on two factors: 1) To improve the current treatment of CH4 in regulatory analysis so that “…they [SC-CH4 estimates] need not be implicitly assigned a value of zero in USG policy assessment,” 50 and that 2) The published estimates are consistent with the SCC approach.

Regarding the first factor, EPA’s justification is that any estimate is better than no estimate. Prior to the Proposed Rule, reductions of CH4 emissions were not monetized and in the Proposed Rule EPA felt compelled to come up with a non-zero value (or it could not justify the Proposed Rule on benefit-cost grounds). The need to come up with a non-zero value for SC-CH4 overlooks the reality that even though the state of research is limited, there are several other (and much lower) estimates in the published literature.

The second reason cited is that the published estimates are inconsistent with the SCC approach and the Marten et al. (2014) paper is the first and only set of direct estimates of the SC-CH4 that are consistent with the IWG’s SCC estimates. The second factor also is not an appropriate justification. Being consistent with the SCC work may be desirable from the EPA’s viewpoint, but it is not a sufficient condition to use such premature estimates as part of the regulatory process since it is contrary to using the best-available science. Both of these reasons are not based on science, but rather on subjective judgment and conform to an arbitrary procedural need. As our comments in the prior section reveal, there remain many technical concerns with the IWG approach as well.

The Federal government has recognized that there is a need for more scientific review of the entire process for estimating a social cost of GHGs, and the IWG has stated it plans to seek technical guidance from independent experts such as the National Academies of Sciences, Engineering, and Medicine to examine the technical merits of the SCC (IWG 2015). We find that a comprehensive scientific review is even more important for the SC-CH4, given the limited

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research to date that we have documented above. Nevertheless, there is evidence of a general impatience on the part of the Administration towards the review process, with the IWG deciding to press ahead in using its SCC estimates because “Academies’ review will take some time, during which Federal agencies will have continued need for estimates of the SCC to use in benefit-cost analysis.”

Deferring the scientific review of the SCC and the SC-CH4 to the future, even after recognizing the need for it, sets a dangerous precedent that undercuts the expectation that Federal regulations be based on best available science.

Conclusions

In a regulatory decision-making process such as that for the Proposed Rule, EPA should be using the best-available peer-reviewed science and not relying on estimates produced by models that have been significantly altered in ways not thoroughly and independently peer reviewed, including by those models’ original developers. Absent such a review, the SC-CH4 estimates that EPA has used cannot be viewed as reliable and do not meet the standards required by Executive Orders that call for the best available scientific, technical, economic, and other information. Given their substantial sensitivity to several key technical issues that we have flagged in our own cursory review, this lack of thorough review is a major concern.

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51 IWG 2015, p. 5.
V. RECALCULATION OF SC-CH4 USING MORE REASONABLE ASSUMPTIONS

In Section III, we identified five specific issues including questionable assumptions (that we do not consider to be the most reasonable) used to compute EPA’s SC-CH4 estimates. These questionable assumptions include the use of a 2.5% discount rate, use of a global geographic scope for benefits instead of a domestic (U.S.) geographic scope, increase radiative forcing due to indirect effects, and use of BaU emissions scenarios that reflect no incremental future mitigation policy.

To provide a quantitative assessment of the sensitivity of the RIA’s estimates of benefits and net benefits to the technical issues, we have re-estimated the SC-CH4 values under several alternative assumptions that we consider more reasonable. All of these alternative SC-CH4 calculations have been made using the same IAMs that were used to compute EPA’s SC-CH4 estimates.

These alternative calculations include:

A. Eliminating from consideration the 2.5% discount rate;

B. Limiting benefits to a domestic geographic scope instead of global geographic scope;

C. Alternative assumptions regarding the indirect effects on radiative forcing; and

D. Eliminating BaU emissions projections as the reference point for computing future damages from a ton of incremental emission that would occur today.

Figure 12 provides a summary range of EPA’s SC-CH4 estimates in 2020 and 2025 based on assumptions we consider either more reasonable or subject to too much uncertainty for EPA to rely on a single point estimate. The values in the “Min” and the “Max” columns show the recomputed low and the high SC-CH4 estimates and percentage change relative to the RIA range assuming different discount rates. The first row (Case RIA) shows the range of SC-CH4 included in the RIA based on mean values using 2.5%, 3.0%, and 5.0% discount rates. Each subsequent row includes a revised range based on different cases we constructed to address some of the technical issues we identified in EPA’s SC-CH4 estimates.

Case A removes from consideration the 2.5% discount rate because it is not appropriate given the shorter atmospheric lifespan of CH4 that reduces concerns about the welfare outcomes of far-future generations.

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52 We have not used the 95th percentile worst-case values in these ranges because that would confuse uncertainty about climate impacts per se with uncertainty in estimating the impact of methane on climate change, which is the concern with EPA’s SC-CH4 estimates that our comments are highlighting.
Case B follows OMB’s guidance of using U.S. benefits for preparing benefit-cost analysis of Federal regulations. Our range is therefore bounded by discount rates of 3% and 5%. Case B shows the range of SC-CH4 estimates when limited to a domestic geographic scope (while also not considering the 2.5% discount rate). The domestic SC-CH4 estimates are averaged across all socioeconomic scenarios from the PAGE and FUND models. We do not use the DICE model because it does not report U.S.-specific benefits.

Case C removes the assumption EPA made on a 40% enhancement of radiative forcing due to indirect atmospheric effects. This case also assumes U.S. benefits and discount rates of 3% and 5%. As with Case B, domestic SC-CH4 estimates are averaged across all socioeconomic scenarios from the PAGE and FUND models, for consistency.

Case D relies on an emissions projection that reflects future emissions control policies to complement current emissions reduction efforts (i.e., the “5th Scenario”), giving no weight to future emissions projections that assume no incremental reductions in GHG emissions in the future (i.e., the four socioeconomic scenarios that reflect BaU policy). For this case, we report domestic SC-CH4 estimates for the 5th Scenario only, for discount rates of 3% and 5%. Again, for consistency with the prior cases, we use only the PAGE and FUND models.

The alternative SC-CH4 estimates show the progressive drop in the SC-CH4 estimates as we move from Case A to Case D, incrementally altering an additional assumption in each case as described above.\(^{53}\) We summarize below the SC-CH4 estimates for each of the alternative cases:

1. **EPA’s range of SC-CH4 estimates per tonne of CH4 in the RIA is $587 to $1,721 in 2020 and $702 to $1,900 in 2025.**

2. **Removing consideration of the 2.5% discount rate.** This lowers the upper end of EPA’s SC-CH4 estimates from $1,721 to $1,309 in 2020 (24% reduction) and from $1,900 to $1,508 in 2025 (21% reduction).

3. **Considering only domestic benefits.** Applying this limitation to the SC-CH4 estimates in the RIA (in conjunction with removing the 2.5% discount rate) reduces the range of SC-CH4 estimates to $106 to $210 in 2020 (reductions of 82% and 88%, respectively) and to $130 to $248 in 2025 (reductions of 81% and 87%, respectively).

4. **The indirect effects on CH4 radiative forcing should not be included as a reference point for calculating the SC-CH4.** Making this change in addition to the above changes reduces the range of SC-CH4 estimates to $69 to $141 in 2020 (reductions of 88% and 92%, respectively) and to $84 to $158 in 2025 (reductions of 88% and 92%, respectively).

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\(^{53}\) As noted in our descriptions above, after Case A, the estimates in this table do not include the DICE model results. Because the DICE model produces the lowest SC-CH4 of the three models, its elimination in Cases B through D probably results in overstatement of the SC-CH4 estimates for these three sensitivity cases.
5. The 5th Scenario should be the reference point for calculating the SC-CH4, rather than the other four scenarios that do not include any response in emissions. Making this change in addition to the above changes reduces the range of SC-CH4 estimates to $58 to $99 in 2020 (reductions of 90% and 94%, respectively) and to $69 to $115 in 2025 (reductions of 90% and 94%, respectively).

Figure 12. Alternative Estimates of SC-CH4 Reflecting Key Methodological Uncertainties

<table>
<thead>
<tr>
<th>SC-CH4, $ per tonne of CH4 (2012$)</th>
<th>(% Change Relative to RIA Range)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2020</td>
</tr>
<tr>
<td><strong>Case</strong></td>
<td><strong>Description</strong></td>
</tr>
<tr>
<td>RIA</td>
<td>RIA Option 2 (2.5%, 3.0%, and 5% discount rates)</td>
</tr>
<tr>
<td>A</td>
<td>RIA Option 2 (3.0%, and 5% discount rates)</td>
</tr>
<tr>
<td>B</td>
<td>Domestic (U.S.) specific SC-CH4 values averaged across all socioeconomic scenarios from PAGE and FUND models.</td>
</tr>
<tr>
<td></td>
<td>Domotic (U.S.) specific SC-CH4 values averaged across all socioeconomic scenarios from PAGE and FUND model without the indirect effects.</td>
</tr>
<tr>
<td>C</td>
<td>Domestic (U.S.) specific SC-CH4 values averaged across all socioeconomic scenarios from PAGE and FUND model without the indirect effects.</td>
</tr>
<tr>
<td>D</td>
<td>Domestic (U.S.) specific SC-CH4 values for the 5th Scenario from PAGE and FUND model without the indirect effects.</td>
</tr>
</tbody>
</table>

Note: The Min and Max values span different discount rates, EPA’s Low and High total costs, and climate benefits. For Cases B, C, and D, we do not report U.S.-specific SC-CH4 estimates from the DICE model because it is a global model and does not include regional details (see Section III.2 for discussion).

The changes in the SC-CH4 translate to changes in the estimated benefits and net benefits for the Proposed Rule, since none of the changes have an impact on CH4 reductions or compliance costs. Using the revised SC-CH4 estimates from Figure 12, we then compared EPA’s net benefits numbers with recalculated net benefits based on our four key assumption changes. The resulting sensitivity cases reflect uncertainties, discussed in the above sections that highlight the extent of EPA’s overestimation of SC-CH4 and their net benefits in the Proposed Rule’s RIA.

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54 Our comments do not address any aspect of the compliance cost estimates or emissions reduction. That does not imply that we endorse them.
Each of the four alternative ranges of SC-CH4 estimates and the resulting net benefits are shown in Figure 13 (for 2020) and Figure 14 (for 2025). Figure 13 shows net benefits in 2020 for a 3% discount rate for the RIA and for the four alternative cases described above. The “red” bar on the graph indicates the total annualized costs – as estimated by EPA, which is constant across all cases. The “blue” bars show climate benefits for the cases. The difference between the black dotted line and the “blue” bars reflect net benefits or net costs.

For Case A, the SC-CH4 in 2020 is the same as that in the RIA because the change in Case A only impacts the range of results by eliminating the 2.5% discount rate from consideration. All of the other scenarios (Case B, Case C, and Case D, which account for domestic benefits only, no indirect effects on radiative forcing and/or using the 5th Scenario) have net costs, rather than net benefits. The net costs could be as large as $120 million to $155 million in 2020 compared to the RIA’s stated net benefits of $44 million to $52 million with a 3% discount rate.

Figure 13. Total Costs, Climate Benefits, and Net Benefits in 2020 for 3% Discount Rate

As with the 2020 results, the net benefits for Case A are unchanged from the RIA. For all other cases, there are net costs that could be as large as $245 million to $380 million (see Figure 14).

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55 Appendix B shows how the climate benefits and compliance costs are spread across the time horizon, and potential payback period. Compliance costs are incurred in the immediate future while climate benefits accrue over a much longer period.
Figure 14. Total Costs, Climate Benefits, and Net Benefits in 2025 for 3% Discount Rate

Figure 21 and Figure 22 in Appendix A show the net costs in 2020 and 2025 for the 5% discount rate cases. With a higher discount rate, the SC-CH4 values are lower resulting in all cases showing net costs, including the EPA RIA estimate.

Figure 15 combines the net benefits/costs results for each case in 2020 and 2025 for the 3% and 5% discount rates (also 2.5% for the RIA case). For each case, the 3% and 5% discount rate results define the upper and lower values of the vertical bars. The figure shows that even using EPA’s SC-CH4 estimates (labeled “RIA”), the Proposed Rule’s net benefits could be negative (or, in other words, the Proposed Rule could have net costs). Figure 15 also shows that when sequentially adjusting for each of the technical issues we have identified, the range of net benefits estimates becomes entirely negative—by more than -$120 million per year and -$240 million even at the ranges’ upper bounds in 2020 and 2025, respectively.

Although Figure 15 does not show results when each of the assumptions are changed individually, we did run the models for the individual changes, as we briefly summarize here. When using a discount rate range of 3% to 5% and changing each of the assumptions that define Case B and Case C individually, net benefits remain negative over the entire range by at least $33 million. When changing assumption that define Case D alone, the net benefits range
remains mostly negative (i.e., -$88 million to +$13 million in 2020 and -$204 million to +$55 million in 2025).\textsuperscript{56}

Given this exceptional degree of sensitivity of the net benefits estimates to alternative reasonable assumptions, the lack of full scientific peer review of the science and approach used to estimate EPA’s SC-CH4 renders it inappropriate for use in making major national policy decisions. We also note that the downward impact on net benefits associated with each individual assumption that we have explored makes it unsupportable for EPA to suggest that the Proposed Rule will produce positive net benefits.

**Figure 15. Range of Net Benefits and Costs in 2020 and 2025 (Millions of 2012$)**

\textsuperscript{56} We do not report the 95\textsuperscript{th} percentile estimates in presenting the ranges for all the cases. We only focus on the mean SC-CH4 values because the 95\textsuperscript{th} percentile values reflect an uncertainty in damages from climate change \textit{per se}, while our focus is on the uncertainties in obtaining a reliable estimate of the incremental climate damages of CH4 emissions.
VI. CONCLUSIONS

Our comments address technical issues with the RIA’s benefits calculations, and their implications for the net benefits estimates. Although our comments do not address any aspect of the compliance cost estimates, that does not imply that we endorse those cost estimates. To provide a quantitative assessment of the sensitivity of the RIA’s estimates of benefits and net benefits to the technical issues that we have identified, we have re-estimated the SC-CH4 values under several alternative assumptions that we consider more reasonable. All of these alternative SC-CH4 calculations have been made using the same IAMs that Marten et al. used to make their SC-CH4 estimates.

We demonstrate that EPA’s estimates of the net benefits are highly uncertain and very likely overstated for multiple reasons:

- The EPA’s SC-CH4 estimates are based upon a single study (Marten et al., 2014) whose estimates are significantly greater than, and inconsistent with, available estimates in other published papers.

- EPA relies on SC-CH4 estimates that reflect global benefits rather than domestic benefits, a practice that is contrary to the Office of Management and Budget’s (OMB’s) Circular A-4 (OMB, 2003) and inconsistent with the theoretical underpinnings of benefit-cost analysis that endow the method with its ability to guide a society towards policies that will improve its citizens’ well-being. Circular A-4 calls for use of domestic benefits, and notes that any estimates of non-domestic benefits should be presented separately. EPA’s use of global SC-CH4 benefits estimates (and failure to even present domestic benefits, which are readily obtained from the same models) results in a significant overstatement of benefits and net benefits of the Proposed Rule.

- The RIA includes a 2.5% discount rate in its range of benefits, which is inconsistent with the short atmospheric lifespan of CH4. Its inclusion overstates the upper end of EPA’s SC-CH4 estimates, and hence its net benefits.

- Marten et al. (2014) have used assumptions regarding indirect effects on radiative forcing from changes in tropospheric ozone and stratospheric water vapor levels that lack clear support from the scientific literature. This assumption, which is uncertain and not validated, could be a substantial source of overstatement in EPA’s SC-CH4 estimates. For example, compared to a zero indirect effects assumption, it increases EPA’s SC-CH4 estimate by about 36% (when using a 3% discount rate).

- EPA’s SC-CH4 estimates are based on an average of five socioeconomic scenarios, four of which assume no incremental policies to reduce emissions in the future (also known as “business as usual” scenarios). Use of scenarios that assume no future emissions control policies to estimate the benefit of reducing a ton of emissions in the near-term overstates the SC-CH4 estimates.
The alternative estimates show that the SC-CH4 estimates could be 90% to 94% lower than the EPA’s SC-CH4 estimates. We also demonstrate that EPA’s SC-CH4 estimates lack the appropriate peer review that is necessary for use in supporting regulatory policy. In the absence of a full scientific peer review of the methodology behind EPA’s SC-CH4 estimates and the degree of sensitivity of the net benefits estimates to alternative reasonable assumptions call into question the reliability of all of the RIA’s benefits and net benefits estimates. It is for these reasons that EPA’s SC-CH4 estimates are too premature and are inappropriate for use in making major national policy decisions.
REFERENCES


## APPENDIX A – ADDITIONAL INFORMATION

### Figure 16. NERA Replication of the Social Cost of Methane (in 2012$ per tonne of CH4)

<table>
<thead>
<tr>
<th>Model</th>
<th>DICE</th>
<th>PAGE</th>
<th>FUND</th>
<th>Average</th>
<th>DICE</th>
<th>PAGE</th>
<th>FUND</th>
<th>Average</th>
</tr>
</thead>
<tbody>
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<td>$1,167</td>
<td>$1,818</td>
<td>$1,507</td>
<td>$1,497</td>
<td>$1,328</td>
<td>$2,176</td>
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<td>$1,225</td>
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<td>$1,008</td>
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<th>FUND</th>
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<th>DICE</th>
<th>PAGE</th>
<th>FUND</th>
<th>Average</th>
</tr>
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### Figure 17. Range of Social Costs of CH4 from the Most Recent Publication - Waldhoff et al. 2014 ($ in 1995)

![Graph showing range of social costs of CH4 from the Most Recent Publication - Waldhoff et al. 2014 ($ in 1995)](image_url)
Figure 18. Summary of SC-CH4 Assuming Global versus Domestic Damages
(Perturbation year=2020, discount rate=5%, 2012$ per tonne of CH4)

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<tr>
<th>IAM</th>
<th>Socioeconomic scenario</th>
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<th>Domestic (U.S.)</th>
<th>% Change Relative to RIA</th>
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Figure 19. Summary of 2020 SC-CH4 Assuming No Indirect Effects on Global Radiative Forcing
(Perturbation year=2020, discount rate=5%, 2012$ per tonne of CH4)

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Figure 20. Range of Net Benefits (2012$ Million)

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<tr>
<td>Net Benefits</td>
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<tr>
<td>A</td>
<td>3%</td>
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<tr>
<td>Total Monetized Benefits</td>
<td>202</td>
<td>214</td>
<td>465</td>
</tr>
<tr>
<td>Total Costs</td>
<td>150</td>
<td>170</td>
<td>320</td>
</tr>
<tr>
<td>Net Benefits</td>
<td>52</td>
<td>44</td>
<td>145</td>
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<tr>
<td>B</td>
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<tr>
<td>Net Benefits</td>
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<tr>
<td>Net Benefits</td>
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<td>(74)</td>
<td>(104)</td>
</tr>
<tr>
<td>A</td>
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<tr>
<td>Total Monetized Benefits</td>
<td>91</td>
<td>96</td>
<td>216</td>
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<td>Total Costs</td>
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<td>170</td>
<td>320</td>
</tr>
<tr>
<td>Net Benefits</td>
<td>(59)</td>
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<td>(104)</td>
</tr>
<tr>
<td>B</td>
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<tr>
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<td>Net Benefits</td>
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<td>Net Benefits</td>
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Figure 21. Total Costs, Climate Benefits, and Net Benefits in 2020 for 5% Discount Rate

![Graph showing total costs, climate benefits, and net benefits in 2020 for 5% discount rate.]

Figure 22. Total Costs, Climate Benefits, and Net Benefits in 2025 for 5% Discount Rate

![Graph showing total costs, climate benefits, and net benefits in 2025 for 5% discount rate.]

NERA Economic Consulting
APPENDIX B - TIMING OF GLOBAL CLIMATE BENEFITS AND TOTAL COSTS

Another issue that we explored is the timing of the benefits and costs. In particular, we explored when the global climate benefits would be realized for cases that have net benefits over the model horizon (i.e., this would not include any of the cases that only focus on domestic benefits since all of these have negative net benefits). In particular, we reviewed the timing of costs and benefits for the DICE and FUND models because we were able to generate annual undiscounted costs. For CH4, an emission reduction today can have climate benefits for several decades. It is important to understand when these benefits are realized in the context of rationalizing public policies that would have an impact on the economy and the society at large in the immediate future.

While capital costs and O&M expenditures are incurred upfront and during the life of the equipment, climate benefits are realized well beyond the life of the pollution control equipment. We decomposed the timing of the costs and global climate benefits to estimate the payback period for an investment that occurs in 2020 with O&M expenditures over the assumed life of the control equipment (8 years). The annual global climate benefits from an incremental ton of emissions avoided in the first year from oil well completions and for an additional seven years from other emissions sources are shown by the blue bars in Figure 23, Figure 25, Figure 27, and Figure 29. These represent global climate benefits from the DICE and the FUND model for the 5th scenario, using a 3% discount rate, and a climate sensitivity of 3. Total costs for achieving CH4 emissions reduction are shown as red bars (note that the capital costs in the first year overlap with the y-axis, but reach $146 million in 2020). Figure 24 shows the cumulative global net benefits in each year through 2300. In the short run, investment costs outweigh global climate benefits, hence negative global net benefits. However, over time global climate benefits add up, and with no additional costs beyond year 8, the cumulative global net benefits become positive around 2070, a payback period of 50 years using 3% discount rate. We do note that the domestic U.S. net benefits would never be positive in this scenario, or any of the other scenarios that we evaluated. The payback period exceeds 300 years if a 5% discount rate is used, see Figure 28 and Figure 30.
Figure 23. Present Value of Spending (red) and Global Climate Benefits (blue) by Year for 5th Scenario (Millions of 2012$)
(Benefits’ timing is based on DICE using the 5th Scenario, climate sensitivity=3, and discount rate=3%)
Figure 25. Present Value of Spending (red) and Global Climate Benefits (blue) by Year for 5th Scenario (Millions of 2012$)
(Benefits’ timing is based on FUND using the 5th Scenario, climate sensitivity=3, and discount rate=3%)
Figure 27. Present Value of Spending (red) and Global Climate Benefits (blue) by Year for 5\textsuperscript{th} Scenario (Millions of 2012$)
(Benefits’ timing is based on DICE using the 5th Scenario, climate sensitivity=3, and discount rate=5%)
Figure 29. Present Value of Spending (red) and Global Climate Benefits (blue) by Year for 5th Scenario (Millions of 2012$)
(Benefits’ timing is based on FUND using the 5th Scenario, climate sensitivity=3, and discount rate=5%)