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

Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives	Docket No. PHMSA-2021-0046 RIN: 2137-AF53

COMMENTS ON PIPELINE SAFETY: SAFETY OF GAS DISTRIBUTION PIPELINES AND OTHER PIPELINE SAFETY INITIATIVES

FILED BY
AMERICAN GAS ASSOCIATION
AMERICAN PUBLIC GAS ASSOCIATION
NORTHEAST GAS ASSOCIATION

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Notice of Proposed Rulemaking
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I. Introduction

The American Gas Association (AGA)[1], American Public Gas Association (APGA)[2], and the Northeast Gas Association (NGA)[3] (jointly "the Associations") submit these comments for consideration by the Pipeline and Hazardous Materials Safety Administration (PHMSA) regarding PHMSA's Notice of Proposed Rulemaking, "Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives" ("proposed rule" or "NPRM")[4].

The Associations support the mandates within the Leonel Rondon Pipeline Safety Act, which is part of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act (PIPES Act) of 2020 and the intent of the proposed regulation. The Associations share PHMSA's goal of enhancing safety and support practicable, reasonable, technical feasible, and cost beneficial rulemakings.

Pipeline safety continues to be the top priority of the Associations and its members. No natural gas company wants an incident to occur, which is why billions of dollars are spent each year to maintain existing systems, find and address potential threats, replace pipe that may no longer be fit for service, train and qualify those working on the natural gas infrastructure, and conduct emergency response drills to better prepare for an incident. When a significant incident does occur, such as the Merrimack Valley Incident, the industry comes together to determine how to prevent a similar incident from occurring in the future. As an example, below are just some of the steps the industry took following the Merrimack Valley incident:

- Industry wide calls to convey what was known about the incident
- Forming a working group to identify practices that could potentially prevent or reduce the possibility of an over-pressure event

[1] Founded in 1918, AGA represents more than 200 local energy companies committed to the safe and reliable delivery of clean natural gas to more than 180 million Americans. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets more than one third of the United States' energy needs.
[2] APGA is the national, non-profit association of publicly owned natural gas distribution systems. APGA was formed in 1961 as a non-profit, non-partisan organization, and currently has over 740 members in 37 states. Overall, there are nearly 1,000 municipally owned systems in the U.S. serving more than five million customers. Publicly owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.
[3] NGA is a regional trade association that focuses on education and training, technology research and development, operations, planning, and increasing public awareness of natural gas in the Northeast U.S. It represents natural gas distribution companies, transmission companies, liquefied natural gas importers, and associate member companies that provide natural gas to over 13 million customers in nine states.
[4] Pipeline Safety: Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives, Federal Register Vol. 88, No. 172 (September 7, 2023).

- Within 90 days, creation of a white paper, "Leading Practices to Reduce the Possibility of a Natural Gas Over-Pressurization Event"
- Promotion of the white paper to the natural gas industry, and government, including through webinars, workshops, conferences, and technical committee meetings

Since the Merrimack Valley incident, natural gas companies with low-pressure distribution systems have utilized the leading practices within the white paper to supplement current practices to reduce the possibility of an over-pressurization event and to improve safety. Some of the practices within the white paper are actually included in PHMSA's proposed rule.

While the Associations offer detailed technical comments on the provisions directly impacting natural gas distribution operators below, there are several general comments that should be considered:

- Low-pressure natural gas systems are unique and provide a critical energy source to millions of Americans.
- Natural gas distribution operators have always taken measures to protect their systems from overpressurization, as supported by the infrequency of overpressurization reportable incidents. These actions intensified immediately following the Merrimack Valley Massachusetts incident in 2018.
- For several provisions in this proposed rule, PHMSA has failed to meet its statutory requirement to conduct a risk assessment that identifies the costs and benefits associated with a proposed standard.
- The implementation timeline for the various provisions within the proposed rule must account for the magnitude of changes that must be implemented concurrently. PHMSA must also recognize the interplay between proposals both within this rule and within the Leak Detection and Repair (LDAR) rulemaking (RIN: 2137-AF51).
- The Associations fully support the proposed requirements that reflect the Congressional mandates in the 2020 PIPES Act. Proposed requirements that go beyond the mandates and impose a burden with no discernible improvement to safety cannot be supported.

A. Industry Efforts to Reduce Pipeline Safety Risk for Low-Pressure Distribution Systems

The 2018 Merrimack Valley incident provided a painful example of what can potentially happen if an overpressurization occurs on a low-pressure distribution system. In response to the 2018 incident, industry quickly provided additional guidance to operators for reducing the impact and likelihood of these incidents, beginning with the AGA publication "Leading Practices to Reduce the Possibility of a Natural Gas Over-Pressurization Event," published November 2018 (see Appendix A). This paper included best practices for design and construction, reducing the likelihood of human error through training, operator qualification (OQ), field oversight, recognition of abnormal operating conditions (AOCs), and recognition of overpressurization-related threats in an operator's DIMP plan[5].

[5] American Gas Association, AGA Technical Note "Leading Practices to Reduce the Possibility of a Natural Gas Over-Pressurization Event"; November 26, 2018.

AGA also published a white paper titled “Skills and Experience for Effectively Designing Natural Gas Systems” in December 2019 (see Appendix B). This publication addressed recommendations made by the National Transportation Safety Board (NTSB) in its accident report[6] related to ensuring appropriate technical competencies for certification of construction drawings. The white paper was issued to “provide guidance to operators on how to develop, maintain, and enhance the key technical competencies required to safely and effectively perform engineering work functions for natural gas systems,”[7] and included best practices for building foundational knowledge tiers in engineering and design, approval of designs, ethical responsibility, management of change (MOC), and continuous improvement.

In 2021, AGA published a white paper titled “Natural Gas Utility Guideline for Developing a Management of Change (MOC) Plan for Engineering Design,” (see Appendix C) intended to “to identify the items that should be considered by natural gas utilities as they develop their MOC procedures, particularly…pertaining to Engineering Design.”[8] This publication focused on elements of a MOC plan for engineering and design, the types of system changes that might require a MOC, process phases for MOC, documentation, and relevant roles and responsibilities.

B. Unique Characteristics of Low-Pressure Gas Distribution Systems

Many of the proposed requirements are specific to low-pressure systems, which are particularly vulnerable to the consequences of any event that may cause overpressurization. Merrimack Valley was a tragic event that reminded the industry of the unique risks associated with low-pressure distribution systems, where options for pressure regulation are limited due to the science of delivering gas at pressure ranges that can adequately meet customer demand and the principles governing the operation of pressure regulation. A critical consideration for PHMSA is that operators must prioritize all efforts to preserve safe and reliable gas delivery, for the hundreds of thousands of customers being served off low-pressure systems. Operators of low-pressure systems know that widespread outages can occur quickly if gas pressure is impacted by an outside event or by the unintended activation of a pressure flow device.

Low-pressure systems continue to be a critical part of the natural gas industry distribution network in the United States. Based on the information collected by the Associations, there are approximately 40,000 miles of distribution main on low pressure systems, including roughly 3.4 million service lines. Each service line provides energy to residences or businesses. Additionally, some service installations for homes include apartment buildings with multiple units.

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[6] National Transportation Safety Board, “Accident Report NTSB/PAR-19/02 PB2019-101365”. https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1902.pdf

[7] American Gas Association, AGA White Paper “Skills and Experience for Effectively Designing Natural Gas Systems”; December 18, 2019. https://www.aga.org/research-policy/resource-library/skills-and-experience-for-effectively-designing-natural-gas-systems/.

[8] American Gas Association, AGA White Paper “Natural Gas Utility Guideline for Developing a Management of Change (MOC) Plan for Engineering Design”; August 2021.

Although the industry continues its efforts to modernize the gas delivery infrastructure, there are unique challenges in replacing and upgrading low-pressure systems. For instance, some communities have been opposed to having gas utilities perform the work necessary to upgrade these systems to a higher-pressure system, and some customers have not wanted to have their gas meters replaced or relocated. Furthermore, operators typically need to install pressure regulator facilities when transitioning their system pressure and may also face limitations involving right-of-way considerations for those facilities.

Low-pressure systems will continue to be a critical and necessary form of gas distribution for the foreseeable future. Accordingly, operators who have low-pressure systems must continue to be provided the flexibility to manage the safety and reliability of these systems, within the framework of new regulations to ensure proper overpressure protection. Operators continually work to balance the need to deliver gas safely with the need to deliver gas reliably, particularly in the winter months where demand spikes and pressures must be carefully monitored.

C. Concerns with NPRM scope and Inadequacy of PHMSA's Preliminary Regulatory Impact Analysis

The comments provided below reflect the Associations' position that significant aspects of the proposed rule exceed Congress' intent in the 2020 PIPES Act and are not technologically, operationally, or economically feasible or reasonable. As a result, the Associations are unable to support certain significant aspects of the proposed rule in its current form. This in no way detracts from our memberships' unwavering commitment to safety. Safety continues to be the industry's top priority, and our members will continue to work proactively to implement actions that will mitigate the risk of overpressurization, strengthen emergency response and enhance public safety.

The Associations also believe that PHMSA's Preliminary Regulatory Impact Analysis (PRIA) contains several critical errors and grossly underestimates the costs associated with implementation of the proposed requirements. PHMSA is required to put forth a credible cost-benefit study for its significant rulemakings. Based on the Associations' review of the PRIA, there are numerous significant areas in the PRIA that are inaccurate, incomplete, or lacking proper context. The Associations have compiled a list of activities in Appendix D that reflect the most significant concerns with the PRIA. **In order for all interested stakeholders to adequately assess the feasibility and economic impacts associated with implementing the proposed rule, it is imperative for PHMSA to put forth a more accurate and comprehensive regulatory impact analysis**.

D. PHMSA's Proposed Dates for Compliance are Neither Reasonable nor Feasible

For the majority of requirements in this NPRM, PHMSA proposes that operators comply within one year of the date of the publication of the rule. For particular provisions, most notably the proposed requirement to upgrade district regulator stations serving low-pressure distribution systems, the Associations believe the one-year compliance timeline is unreasonably short, and could have significant unintended negative consequences to pipeline safety outcomes. The risk of rushing final rule requirements is real, and is likely to increase the risk of reportable incidents related to overpressurization of low-pressure distribution systems.

The proposed requirements include a broad range of changes to operator's procedures and will result in substantial MOC process considerations for data collection practices, design and construction of pressure regulation facilities, work management systems, information technology systems, equipment, supply chain limitations, staffing, training, bargaining unit contract negotiations/agreements, OQ programs, securing supplemental resources and negotiating associated jurisdictional rate relief. Operators will need significantly more than 12 months to take all the necessary actions for compliance with certain aspects of the NPRM, particularly with design and capital improvements associated with upgrading and/or replacing district regulator stations. Any program involving retrofitting existing stations with additional overpressure protection will be a significant undertaking requiring planning, design and program oversight. In some regions of the country, particularly where low-pressure distribution systems prevail, enhancements prescribed in the NPRM number in the thousands. Securing materials and resources as well as evaluating each facility for potential retrofitting or replacement will require thoughtful evaluation of timeframes.

Additional challenges facing operators include restructuring of emergency response plans, standing up systems for rapid communication with customers and communities, working collaboratively with first responders, and various DIMP enhancements. These efforts will require acquiring and implementing IT solutions that often require multiyear planning, development, and procurement.

Furthermore, given that the LDAR rulemaking is not expected to be finalized, based on the most recent Unified Regulatory Agenda, until May 2024, considerable uncertainty remains regarding how implementation of these two substantial rulemakings will need to be aligned, particularly with regard to MOC requirements, interactions between relief valve device requirements, and new requirements for construction oversight that will necessarily encumber the replacement of leak-prone pipe on low-pressure distribution systems.

The Associations respectfully request that the final rule feature effective dates that are practical and reasonable to facilitate a compliance glidepath that meets the intent of the proposal and takes into consideration the extensive changes being proposed in the parallel LDAR rulemaking. Operators cannot prudently begin implementation efforts until they know the outcomes of both final rulemakings.

II. Technical Comments

A. Distribution Integrity Management Programs (Subpart P)

The Associations support PHMSA's efforts to address the congressional mandates in the PIPES Act of 2020 concerning changes to Distribution Integrity Management Programs (DIMP), and fully support efforts to implement the valuable lessons learned from the overpressurization of a low-pressure system in Merrimack Valley. Congress mandated in Section 202 of the PIPES Act of 2020 that PHMSA promulgate a rule requiring –

> *each distribution integrity management plan developed by an operator of a distribution system includes an evaluation of—*
>
> *(i) the risks resulting from the presence of cast iron pipes and mains in the distribution system; and*
>
> *(ii) the risks that could lead to or result from the operation of a low-pressure distribution system at a pressure that makes the operation of any connected and properly adjusted low-pressure gas burning equipment unsafe, as determined by the Secretary.*
>
> *(B) CONSIDERATION.—In carrying out subparagraph (A)(ii), the Secretary shall ensure that an operator of a distribution system-*
>
> *(iii) considers factors other than past observed abnormal operating conditions (as defined in section 192.803 of title 49, Code of Federal Regulations (or a successor regulation)) in ranking risks and identifying measures to mitigate those risks; and*
>
> *(iv) may not determine that there are no potential consequences associated with low probability events unless that determination is otherwise supported by engineering analysis or operational knowledge.*

The Associations believe that it is imperative that PHMSA:

1. Promulgate a rule consistent with the Congressional mandate language and that meets Congress's intent: verification that DIMP programs address the threats known to contribute to the Merrimack Valley incident.
2. Does not require prescriptive inclusion of generic threats in DIMP risk models, contradicting the DIMP fundamental requirement to "know your system."
3. Continues to focus on performance-based measures in DIMP rather than adding regulatory requirements that align with a more prescriptive approach which does not actually elevate safety.

4. Does not utilize DIMP to be the vehicle to "backdoor" design/construction standards that PHMSA wishes to apply to existing facilities, in contravention of nonapplication clause 49 U.S.C. § 60104(b)[9].

The Associations believe that some proposed revisions to Part 192, Subpart P are problematic, which would thereby render it an ineffective and unreasonable regulation if such revisions are adopted. PHMSA is reminded that under DIMP, operators are required to analyze their pipeline systems to identify threats to pipeline integrity and rank by risk their relative importance. Operators are then required to take actions to address these threats and mitigate the risk to their system. These actions can be programmatic, with the understanding not all actions must be immediate or accelerated in nature. Operators must identify those risks on their pipeline systems where an accident could result in significant consequences, prioritize these risks, evaluate risks periodically, address abnormal operating conditions, and evaluate the results to validate that their programs improve the integrity of their pipelines. Integrity management requires operators to use a risk-based approach to manage the safety of their own pipeline systems.

1) *PHMSA should harmonize DIMP-related records requirements.*

PHMSA should utilize the same terminology as the NTSB and Congress pertaining to distribution asset records: "traceable, reliable, and complete."

In the proposed changes to § 192.1007(a), PHMSA references proposed § 192.638(c), which uses the "traceable, verifiable, and complete" to describe records at district regulator stations that are critical to ensuring proper pressure control. However, 49 U.S.C. 60102(t)(1) mandates PHMSA to require operators to identify and manage "traceable, reliable, and complete" records. PHMSA states that they "interpret 'reliable' and 'verifiable' to mean the same because "both verifiable and reliable would mean to prove that a record is trustworthy and authentic" and that "a record is considered reliable if it is verifiable and vice versa."[10] The word reliable is defined as: "consistently good in quality or performance; able to be trusted."[11] The word verifiable is defined as: "able to be checked or demonstrated to be true, accurate, or justified."[12] Although similar, the Associations have concerns with PHMSA's assumption that these words are interchangeable and recommends the use of the word "reliable" vs. "verifiable." The Associations recommend that the type of records that PHMSA wishes collected in § 192.1007(a)(3) should be limited to records needed for the operator to perform its DIMP risk analysis.

Finally, the Associations also suggest that the requirement in § 192.1007(d)(2)(i) to identify, maintain, and obtain pressure control records be struck entirely. As the

[9] 49 U.S. Code § 60104(b): A design, installation, construction, initial inspection, or initial testing standard does not apply to a pipeline facility existing when the standard is adopted.
[10] FR at 61782.
[11] reliable - Oxford Languages
[12] verifiable - Oxford Languages

proposed regulatory text indicates, this requirement is already articulated in §§ 192.638 and 192.1007(a)(3), and including it in § 192.1007(d)(2)(i) is redundant and potentially confusing.

2) ***PHMSA should not require operators to consider threats that are not relevant to their distribution systems.***

The foundation of the DIMP regulation is built upon subject-matter expertise on the operating conditions, material attributes of the system, and the environment in which the natural gas distribution system operates. Prescriptive inclusion of threats (with little practicable room to deviate) is contradictory to operator lead integrity management and places the regulator in the role of risk manager.[13]

PHMSA is proposing that operators must fully incorporate and address all potential impacts of a long list of extreme weather events, regardless of whether such a weather event has ever been experienced in the life of the distribution pipeline system. While PHMSA provides some allowance to omit these weather events from the risk analysis, PHMSA requires detailed documentation and an explicit allowance by the agency to do so. This is impractical for both operators and the agency. PHMSA points to climate change and changing weather patterns as the justification for. requiring operators to anticipate unprecedented extreme weather events. This is in contradiction of the requirement to "know your system" and would require Operators to know a hypothetical weather scenario that does not currently exist and might not ever exist. For example, an operator in Nebraska will now have to incorporate hurricanes into their relative risk model unless they choose to notify PHMSA of their omission. This would result in resources being expended which could otherwise be devoted to mitigate actual and current risks to the system.

It should also be noted that PHMSA's notification system for omission of "low-probability events" is a process that will likely only be utilized by larger natural gas distribution systems with in-house engineering and meteorology expertise. Most natural gas distribution systems in this country do not directly employ engineering expertise, and certainly not engineering experts on weather events and probabilistic risk modeling. PHMSA has effectively created a provision that is out of reach of most natural gas distribution systems and one that also has no discernible value towards improving safety.

[13] PHMSA, "Distribution Integrity Management Program (DIMP) History", 2011. https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/gas-distribution-integrity-management/61706/historyofdimp06152011.pdf

3) ***PHMSA should understand that pipeline system age is a contributing risk factor, not a distinct system threat.***

The age of a pipeline system and the age of the assets within that system are not threats to that system, they are contributing factors that can impact the magnitude or consequence of a leak or failure. On its own, the age of piping and components is only a contributing risk factor for certain material types (e.g., unprotected and/or uncoated steel, certain legacy manufacturers of plastic). Typically, other risk factors such as cathodic protection, soil conditions, and installation practices factor significantly in time-dependent risks.

All age-adjacent threats identified by PHMSA are likely to be considered by other parts of a DIMP plan.

4) ***Operators should not be required to consider overpressurization of low-pressure distribution systems as a standalone threat within their DIMP plans.***

PHMSA incorrectly incorporates overpressurization as a threat to low-pressure natural gas distribution systems. Overpressurization is not a threat. It is an outcome that may result from other threats.

Generally, overpressurization events are a result from other existing threats, such as: incorrect operations during tie-ins and regulator station maintenance; equipment failure (e.g., leaking bypass valves, failure of working and monitoring regulators, failure of relief valves, etc.); or excavation damage of regulator station control lines.

Creating a new standalone threat of overpressurization for the DIMP risk model would not be logical as the root cause of such an outcome is already covered under the current threat categories. Since the Merrimack Valley incident in 2018, distribution operators have assessed the possibility of an overpressurization event occurring on their system, and have been working to address the scenarios by taking actions as identified in AGA's "Leading Practices to Reduce the Possibility of a Natural Gas Over-pressurization Event"[14] white paper.

The Associations are also concerned about PHMSA's proposal to require evaluation of potential consequences associated with low-probability events (per § 192.1007(c)(3)(ii)). Any "event" associated with risk will necessarily have non-zero potential consequences, otherwise it would not be an event. Realistically, an operator is the only one in a position to determine whether the probability and consequence of an event are sufficiently low to conclude the event does not pose a risk of sufficient magnitude to require action. Such a conclusion can be made through the development

[14] AGA, "Leading Practices to Reduce the Possibility of a Natural Gas Over-Pressurization Event" Technical Note; November 26, 2018 (see Appendix A).

of an acceptable risk tolerance level or “As Low As Reasonably Practicable” (ALARP) analysis. In any case, the Associations recommend qualifying § 192.1007(c)(3)(ii) to require that the documented engineering analysis demonstrate that the event results in no *significant* consequences.

Moreover, while the Associations acknowledge the necessity of performing a documented engineering analysis (required by § 192.1007(c)(3)(ii)) to demonstrate that certain low-probability events that could result in an overpressurization do not have significant potential consequences, the proposed follow-up notification to PHMSA (as per § 192.18) provides no apparent safety benefits. Mandating a notification to PHMSA of the documented engineering analysis merely introduces a significant reporting burden for Operators and creates uncertainty as to how and when such analyses can be used within a DIMP plan. Accordingly, the Associations recommend striking the required PHMSA notification proposed in § 192.1007(c)(3)(ii).

5) ***DIMP plans must not be used to circumvent the nonapplication clause (49 U.S.C. § 60104(b)).***

The Associations remind PHMSA that the nonapplication clause prescribed in 49 U.S.C. § 60104(b) stipulates that “a design, installation, construction, initial inspection, or initial testing standard does not apply to a pipeline facility existing when the standard is adopted.” The Associations maintain that the DIMP rule must not be a dumping ground or backdoor for new design or construction standards that PHMSA wishes to apply to existing facilities. Applying the design standards of § 192.195 within the DIMP rule is an unwelcome precedent for circumventing the nonapplication clause, and must be avoided in this rulemaking.

The major concerns raised above, coupled with the additional edits to Part 192, Subpart P below, provides language that allows an Operator to revise and implement a technically feasible and practicable DIMP program enhancing what is already being done through an operator’s current DIMP. This will enable the fundamental seven elements of an operator’s DIMP to address the congressional mandates, and to implement lessons learned from the overpressurization of the low-pressure system incident in Merrimack Valley.

The Associations recommend[15] the following edits to § 192.1007:

§ 192.1007 What are the required elements of an integrity management plan?
* * * * *

(a) * * *

(3) Identify additional information and provide a plan for gaining that information over time ~~(including the records specified in § 192.638l)~~ through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

* * * * *

(b) Identify threats. The operator must consider the following categories of threats to each gas distribution pipeline: c~~C~~orrosion (including atmospheric corrosion);~~,~~ natural forces (~~including~~ such as extreme weather, land movement, ~~and~~ or other geological hazards)~~,~~; excavation damage, other outside force damage, material (including the presence ~~and age~~ of ~~pipes such as~~ cast iron~~, bare steel, unprotected steel, wrought iron, and historic plastics with known issues~~) or welds;~~,~~ equipment failure;~~,~~ incorrect operations;~~,~~ ~~overpressurization of low-pressure distribution systems;~~ and other ~~issues~~ threats that ~~could threaten~~pose a risk to the integrity of ~~its~~ a pipeline. An operator must also consider the age of the system, pipe, and components in identifying threats. An operator must consider reasonably available information when attempting to ~~consider~~identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records (including atmospheric corrosion records), continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

(c) Evaluate and rank risk.

(1) General. An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.
(2) Certain pipe with known issues. An operator must, no later than **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, evaluate the risks in the distribution system resulting from pipelines with

[15] All regulatory text recommended by the Associations in these comments use the following color scheme: blue underline for PHMSA's proposed additions supported by the Associations; ~~red strike-through~~ for PHMSA's proposed deletions supported by the Associations; purple underline (or ~~purple strike-through~~) for revisions suggested by the Associations.

known issues based on the material (including~~,~~ cast iron~~, bare steel, unprotected steel, wrought iron, and historic plastics with known issues~~), design, ~~age~~ vintage, or past operating and maintenance history.
(3) *Low-pressure Distribution Systems*. An operator must, no later **than [INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, evaluate the risks that could lead to or result in ~~from the operation~~ overpressurization of a low-pressure distribution system ~~at a pressure that makes the operation of any connected and properly adjusted low-pressure gas burning equipment unsafe~~. In the evaluation of risks, an operator must:

(i) Evaluate factors other than past observed abnormal operating conditions (as defined in § 192.803) in ranking risks, including any known industry threats, risks, or hazards to public safety that could occur on its system based on knowledge gained from available sources;

(ii) Evaluate potential consequences associated with applicable low-probability events that could result in an overpressurization of a low-pressure distribution system unless a determination, supported and documented by an engineering analysis, or an equivalent analysis incorporating operational knowledge, demonstrates that the event results in no significant~~potential~~ consequences~~, and therefore no potential risk~~. ~~An operator must notify PHMSA and State or local pipeline safety authorities, as applicable, in accordance with § 192.18 within 30 days of making such a determination. The notification must include the following:~~

~~(A) Date the determination was made;~~
~~(B) Description of the low-probability event being considered;~~
~~(C) Logic Justification supporting the determination, including information from an engineering analysis, or an equivalent analysis incorporating operational knowledge;~~
~~(D) Description of any preventive and mitigative measures actions taken, including any measures considered but not taken;~~
~~(E) Details of the low-pressure system applicable to the event that results in no potential consequence and risk, including, at a minimum, the miles of pipe, number of customers, number of district regulators supplying the system, and other relevant information; and~~
~~(F) Written statement summarizing the documentation provided in the notification.~~

(iii) Evaluation of the configuration of ~~primary and any secondary~~ overpressure protection installed at district regulator stations (such as a relief valves, monitoring regulators, or automatic shutoff valves), the availability of gas pressure monitoring at or near overpressure protection equipment, and the likelihood of any single event (such as excavation damage, natural forces, equipment failure, or incorrect operations), that ~~either immediately or over time,~~ could result in an overpressurization of the low-pressure distribution system.

* * * * *

(d) Identify and implement measures to address risks.

(1) *General.* ~~Determine~~ An operator must identify and implement, as appropriate, measures ~~designed~~ to reduce the risks ~~from~~ of failure of its ~~gas~~ distribution pipeline system, consistent with the evaluation required by § 192.1007I. ~~The measures identified and implemented must address, at a minimum, risks associated with the age of pipeline components, the overall age of the system and components, the presence of pipes with known issues, and overpressurization of low-pressure distribution systems.~~ These measures must include an effective leak management program (unless all leaks are repaired when found).

(2) *Minimization of Overpressurization of Low-Pressure Distribution Systems.* An operator must, no later than **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, implement the following ~~preventive and mitigative~~ measures to minimize the risk of overpressurization of a low-pressure distribution system that could be the result of any single event or failure:

~~(i) Identify, maintain, and obtain, if necessary, pressure control records in accordance with §§ 192.638 and 192.1007(a)(3).~~

~~(ii)~~ Confirm and document that each district regulator station serving a low-pressure distribution system meets the requirements of § 192.195(c)(1) through (3) by **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**. If an operator determines that a district regulator station serving a low-pressure distribution system does not meet the requirements of § 192.195(c)(1) through (3), then the operator must take alternative measures based on the unique characteristics of its system to minimize the risk of overpressurization of a low-pressure distribution system. The operator must take these alternative measures no later than:

(A) **[INSERT FIFTEEN YEARS AFTER THE PUBLICATION DATE OF THE RULE]** for any district regulator station serving a low-pressure distribution system with a full-capacity pressure relief device or slam-shut device not otherwise meeting the requirements of § 192.195(c)(1) through (3), or

(B) **[INSERT TEN YEARS AFTER THE PUBLICATION DATE OF THE RULE]** for all other district regulator stations serving a low-pressure distribution system not otherwise meeting the requirements of § 192.195(c)(1) through (3).

~~by **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, the operator must take either of the following actions:~~

~~(A) Upgrade the district regulator station to meet the requirements of § 192.195(c)(1) through (3), or~~

~~(B) Identify alternative preventive and mitigative measures based on the unique characteristics of its system to minimize the risk of overpressurization of a low-pressure distribution system. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of implementing any alternative measures. The notification must be made in accordance with § 192.18(c) and must include a description of proposed alternative measures, identification and location of facilities to which the measures would be applied, and a description of how the measures would ensure the safety of the public, affected facilities, and environment.~~

B. *Emergency Response Plans (Section 192.615)*

Emergency Response Plans

PHMSA proposes significant changes to § 192.615 related to natural gas operators' Emergency Response Plans (ERP). The proposed changes include expanding the emergencies prompting use of ERPs to address Congressional mandates and to include pipeline rupture scenarios. The proposal also includes adding prescriptive requirements for gas distribution operators' communication procedures with the public and first responders. Lastly, PHMSA proposes gas distribution operators develop and implement a voluntary opt-in system that enables rapid communication with customers in the event of a gas emergency.

In Section 203 of the PIPES Act of 2020, Congress mandated that PHMSA promulgate a rulemaking that updates the ERP regulations for distribution pipeline systems. The Associations support Congress and PHMSA in efforts to strengthen relationships between natural gas distribution operators and the first responders that serve in their service areas. However, the Associations believe that PHMSA went beyond Congress' mandates and failed to adequately consider all second and third order impacts of its proposals.

PHMSA's proposal applies new requirements to emergency scenarios currently in regulation, which was not mandated by Congress.

Existing § 192.615(a)(3) provides a list of the four types of emergencies operators should include in their ERPs:

1. Gas detected inside or near a building
2. Fire located near or directly involving a pipeline facility
3. Explosion occurring near or directly involving a pipeline facility
4. Natural disaster

Congress mandated additional requirements for four different types of emergencies that involve an unintended release of gas from a pipeline system that result in –

1. A fire related to an unintended release of gas
2. An explosion
3. 1 or more fatalities
4. The unscheduled release of gas and shutdown of gas service to a significant number of customers, as determined by the Secretary

In the proposed rule, PHMSA proposes to expand the requirements for ERPs by requiring natural gas distribution operators to:

A. Establish and maintain communication with the general public in the operator's service area as soon as practicable during a gas pipeline emergency and
B. Notify customers through a voluntary opt-in system when emergencies are occurring on the distribution system.

These new requirements apply not only to the four new types of emergencies proposed by PHMSA, but also applies to the four existing emergencies found in current § 192.615(a)(3)(i)-(iv). The Associations recommend that PHMSA limit the applicability of the new requirement to only those emergency scenarios within proposed § 192.615(a)(3)(ii)(iii), (vi), and (vii) that were specifically mandated by Congress. Requiring immediate notification to the public and customers of the emergencies currently identified in § 192.615(a)(3) (i), (iv) will not enhance pipeline safety nor benefit the public. For example, when a hurricane or other natural disaster is impacting a community where there is a natural gas pipeline system, there is only a need for the pipeline operator to communicate with the public or their customers if an actual pipeline emergency has occurred. Requiring general communication about the natural disaster by a pipeline operator would become extra noise in a stream of communications being shared by other public safety officers.

Natural gas distribution operators have worked diligently through their Public Awareness programs to educate the public on the importance of notifying their local natural gas utility when there is a natural gas odor or suspected natural gas leak. This effort results in millions of "odor calls" from the public and customers – many of which are not natural gas at all, but household chemicals, sanitary sewer, animals, or other sources. Natural gas distribution operators prioritize leak calls from the public as their highest priority and respond promptly to determine the cause of the odor and make the area safe. In some instances, there is a small, inconsequential leak near a customer meter that is remedied quickly. In other instances, there is a gas leak on non-jurisdictional piping within the premise. Natural gas distribution operators take actions to ensure the internal leak is addressed, either by isolating a leaking appliance or turning off the gas to the customer until the inside piping leak is remedied. In both situations (a) a small leak on a meter set or (b) a leak on an appliance or inside piping, PHMSA's proposal would require the operator to call the local Public Service Answering Point (PSAP), notify the public, and communicate with all their customers. The Associations do not believe this was Congress nor PHMSA's intent and has recommended revisions to the code language to address this overreach. The Associations support the continued activation of Emergency Response Plans in these situations but disagree with the broad communication requirements that have been proposed. There should not be an expectation to call a PSAP or notify the public and customers unless there is an actual emergency.

See the redlined § 192.615 at the end of this section for the Associations recommended edits.

PHMSA should narrow the rupture scenario necessitating activation of Emergency Response plans.

In the NPRM, PHMSA also proposes four alternative emergency scenarios for § 192.615(a)(3), two of which are linked to a Congressional mandate and two are not: "notification of a potential rupture (see 192.635)" and "any other emergency deemed significant by the operator."

Notification of a potential rupture does not constitute an emergency. It is worth noting that Section 203 of the PIPES Act specifically mandates that PHMSA update regulations to establish communication "as soon as practicable, beginning from the time of confirmed discovery [emphasis added]." The pipeline safety community has already contemplated the difference between notification of a potential emergency and the confirmed discovery of an emergency. This discussion led to the definition of *Confirmed discovery* in § 191.3,

> "*Confirmed discovery* means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation."

The Associations agree with Congress and strongly recommend that PHMSA modify § 192.615(a)(3)(v) to "Confirmed discovery of a rupture (see § 192.635)."

Natural gas distribution operators should only be required to communicate with the public and customers on significant incidents originating from their natural gas distribution systems.

Congress also specified that the emergencies warranting additional mandates should originate from the natural gas distribution system, "by the operator of a gas pipeline emergency involving a release of gas from a distribution system of that operator."[16] The Associations recommend that PHMSA maintain this distinction in § 192.615(a)(3) (ii) and (v) by clarifying that an operator is responsible for activating these critical emergency response procedures when there is fire related to an unintended release of gas or a fatality due to a release of gas "from a distribution system".

The Associations recommend PHMSA increase the threshold for a customer outage resulting from an unintentional release of gas from 50 customers to 270 customers. PHMSA should also prioritize prolonged outages.

Congress mandated PHMSA define the size of a customer outage due to the unscheduled release of gas that constitutes an emergency. PHMSA proposed that threshold lay at 50 customers, or 50% of the customers for those natural gas systems serving less than 100 customers. PHMSA justifies this proposed threshold by stating the agency "reviewed the data for all reportable gas distribution incidents from 2010 to 2021 and averaged the number of residential, commercial, and industrial customers affected by those incidents."[17]

There were 1,396 reportable incidents on natural gas distribution systems between 2010 and 2023; however, 691 of those incidents impacted only one customer or no customers

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[16] 49 U.S.C. 60102(r)(1) – "establishing communications with first responders and other relevant public officials, as soon as practicable, beginning from the time of confirmed discovery, as determined by the Secretary, by the operator of a gas pipeline emergency involving a release of gas from a distribution system of that operator that results in – "

[17] The Associations were unable to determine how PHMSA came to that average. When evaluating data from 2010 through 2023, the average number of customers impacted by a reportable incident was 141 customers.

at all. Some examples of these reportable incidents are: (a) vehicular damage to above ground piping which results in a significant release of gas and (b) equipment malfunctions that lead to an injury of a gas distribution system employee. When evaluating the 705 reportable incidents that impacted two or more customers, on average 270 customers were impacted. Therefore, the Associations recommend PHMSA raise its threshold for "significant number of customers" from 50 to 270.

The Associations believe that Congress included this provision in the mandate because it believed it was important for customers to receive timely information during prolonged gas outage scenarios. However, the proposed rule does not limit communication to affected customers, it also includes communicating with PSAPs and the general public. Because of this broad audience, only those situations where gas service cannot be quickly restored should meet the definition of "emergency" per § 192.615(a)(3). Natural gas distribution operators will know within moments how quickly they will be able to restore gas service, and therefore, will know whether or not the scenario necessitates the utilization of their ERP and all associated communication requirements. Therefore, the Associations recommend PHMSA include consideration for outage time in the description of this type of an emergency.

PHMSA should remove "any other emergency deemed significant by the operator" from the regulatory text.

Natural gas pipeline operators are always welcome to expand their practices and procedures beyond those required by regulation. If an operator decides to apply the procedures prescribed by 192.615 to other types of emergencies, they are free to include those emergencies in their Emergency Response Plan. An explicit allowance in 192.615(a)(3) is not necessary and may cause regulatory confusion.

When utilizing the NIMS framework during an emergency, information is controlled and disseminated by a Public Information Officer.

Many gas distribution operators have fully or partially implemented utilization of the Federal Emergency Management Agency (FEMA) National Incident Management System (NIMS) model. "NIMS guides people and organizations in all levels of government, Nongovernment Organizations (NGO), and the private sector to work together to prevent, protect against, mitigate, respond to, and recover from incidents."[18] The framework includes four NIMS Command and Coordination systems: Incident Command System (ICS), the Emergency Operating Center (EOC), the Public Information Officers (PIO) operating within the Joint Information System (JIS), and the Multiagency Coordination (MAC) group.[19]

According to FEMA's NIMS Basic Guidance for Public Information Officers, the "PIO interfaces with the public, media, various agencies, and the private sector to meet incident-related information needs" and "in incidents that involve PIOs from different agencies, the [Incident Commander] (IC) or Unified Command designates one person as the lead PIOs." During natural gas pipeline emergencies, the IC may be a representative from the fire department and the PIO may be a public official, unless the natural gas operator is large enough to employ its own. In most instances, the gas utility operator provides information to the PIO, who then disseminates it appropriately.

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[18] NIMS Basic Guidance for Public Information Officers. https://www.fema.gov/sites/default/files/documents/fema_nims-basic-guidance-public-information-officers_12-2020.pdf

[19] https://www.fema.gov/sites/default/files/documents/fema_nims_training-program-may-2020_0.pdf

In the PRIA PHMSA has requested comment on "the benefit and feasibility of requiring an ICS in this or another rulemaking, as well as the best practices that would inform such a regulatory standard." It is the Associations position that requiring ICS through this rulemaking would fall far outside of the scope of this rule and would be an inappropriate stretch from what has been included in this proposed rule. The Associations see utilization of ICS as a good practice that must be mutually discussed, drilled, and practiced between an operator and their local emergency responders. Numerous stakeholder meetings and workshops should be held on this topic before any proposals to require use of ICS in pipeline safety regulations are proposed.

<u>*PHMSA's prescription on the content communicated with the public goes well beyond Congress's mandate and what is prudent to share during an emergency.*</u>

Congress mandated that PHMSA publish a regulation

> "establishing general public communication through an appropriate channel –
>
> (A) as soon as practicable, as determined by the Secretary, after a gas pipeline emergency described in paragraph (1); and
>
> (B) provides general information regarding -
>
> (i) the emergency described in paragraph (A); and
>
> (ii) the status of public safety"

Congress very specifically notes that this communication should happen through "an <u>appropriate</u> channel". [emphasis added] PHMSA fails to include this important distinction in its proposal, which results in a requirement for operators to directly issue all communications to the general public regarding an emergency. As discussed previously in these comments, the requirement for operators to directly communicate with the public circumvents NIMS procedures and may result in significant conflict between the natural gas distribution pipeline operators and the public safety officials they are working with during an emergency. The Associations strongly recommend that PHMSA include this important clarification in the regulatory text as it provides operators the flexibility to work *with* their local emergency responders instead of *against* or around them. Furthermore, PHMSA's prescriptive requirement to disseminate information to the general public through "one or more formats or media accessible to the population in the operator's service area" should be removed as it circumvents the practice of using "appropriate channel" for communication.

Congress mandated that the natural gas distribution operator's emergency procedures include communication "<u>after</u> a gas pipeline emergency." [emphasis added] PHMSA's proposal is to require "communication with the general public in the operator's service area as soon as practicable <u>during</u> a gas pipeline emergency." [emphasis added] During a pipeline emergency an operator is focused on maintaining safety for customers, the public, and employees. Any pressure to communicate during the event may result in a loss of focus on making the situation safe or could result in inaccurate or incomplete information shared. Furthermore, in some situations, the emergency event duration is only a short moment in time thus nullifying the ability to communicate <u>during</u> the event. Congress understood this and mandated that this communication happens as soon as practicable <u>after</u> the emergency. The Associations recommend that PHMSA modify the regulatory text to better align with Congress's mandate.

PHMSA also significantly expands the information to be communicated with the public beyond what was mandated by Congress. Congress only mandated two items to be communicated: (1) the emergency and (2) the status of public safety. PHMSA significantly expanded this list to also include: (3) the status of the emergency, (4) status of pipeline operations, (5) a timeline for expected service restoration, and (6) directions for the public to receive assistance. PHMSA also proposes a requirement to update the public whenever the information changes. Pipeline emergencies can be complex and often evolve over time. Requiring operators to quickly communicate this information and update the public whenever it changes may ultimately lead to confusion and misunderstandings, as they may only be estimates. The Associations recommend that PHMSA narrow the information to only (a) information regarding the emergency and (2) the status of pipeline operations affected by the gas pipeline emergency. The Associations appreciate that PHMSA recognizes the role natural gas distribution operators play in maintaining public safety, but this does not mitigate the need for public safety officers to communicate the status of public safety.

PHMSA's requirement to determine the concentration of non-English speakers goes beyond available Federal data and is unnecessary.

Operators currently utilize Federal census data to identify approximate numbers of the public that are non-English speaking individuals for compliance with 192.616 – *Public Awareness.* The data enables operators to understand the number of individuals in a service territory that are non-English speaking, but the ability to measure the concentrations of those individuals within the extents of the service territory in a more detailed manner is beyond the abilities of operators both large and small. Concentration is variable. The public is mobile, so concentration changes between workdays and evenings, weekends, and weekdays. Focusing on significant populations as a percentage of the public is certainly more than adequate to meet the requirements of Congress.

Congress only mandated that gas distribution operators develop and implement a voluntary opt-in system for customer notification. PHMSA should not prescribe details on how those systems are to be maintained as that prescription limits the flexibility and scalability of those systems for operators of various sizes.

Of the 1,440 natural gas distribution operators, approximately 650 serve less than 1,000 customers. Various market research suggests that approximately 15% of customers will opt-in for notifications from their utility providers. This equates to less than 150 customers receiving notifications about very specific pipeline emergency events from a large group of PHMSA regulated distribution operators. The Associations believe there are numerous systems or methodologies an operator may use to "rapidly communicate" with these customers.

PHMSA's prescriptive requirements on how the methodology must work and be maintained suggests the utilization of individual phone numbers of customers. Maintenance of customers' phone numbers is challenging because they are never static nor consistent and as noted before, individuals could move in or out of the service territory. In PHMSA's PRIA they "assume that operators would communicate with their customers via telephone, cellphone, text message, or email, requiring a public relations specialist to spend 2 hours of time per gas pipeline emergency."[20] PHMSA then absorbs the cost associated with its prescriptive proposal for maintenance in those 2-hours, without ever acknowledging the separate costs to document and maintain a system in the specific way its proposal outlines.

Congress did not mandate how these systems are to be maintained or the documentation needed for their maintenance. By prescribing exactly how operators are to test and

[20] PHMSA PRIA. Page 28.

maintain their systems, PHMSA is prescribing specific methodologies for communication for operators to use, which will limit the flexibility and likely limit the effectiveness of this voluntary opt-in system. The Associations strongly recommend that PHMSA remove all proposals concerning the maintenance of the systems to allow for maximum flexibility and scalability for these communication methodologies.

PHMSA should carefully consider the difference between the public and customers and what information is appropriate to be disseminated to each stakeholder group.

In a few instances throughout the proposed rule, PHMSA conflates different stakeholder groups: the general public, the affected public, customers impacted by an emergency, all customers, and customers in a service area. Each one of these groups is impacted differently by emergencies resulting from a natural gas pipeline. Careful consideration concerning what information is shared with them, when it is shared, and any regulatory requirement to do so is prudent. Some of the recommended changes to the regulatory text offered by the Associations below seek to better define what information is appropriate to share with each of these stakeholder groups.

PHMSA's estimates for the costs to comply are flawed and not consistent with its proposal.

PHMSA vastly underestimates the impact of the proposed changes to Emergency Response Plans. In the PRIA, PHMSA states they "assumed that all gas distribution, master meter, small LPG, affected gas gathering, and gas transmission operators would each incur a one-time burden of 6 hours to revise their emergency response plans to incorporate the new types of gas emergencies, notifications to PSAPs in the event of a gas emergency, and, for gas distribution operators, communication with customers and the general public."[21]

PHMSA goes on to assume that the changes to rupture and identification emergency response procedures will require a small incremental change to annual operations and training requirements: 30 more minutes of training per employee per year. However, PHMSA fails to include the time it will take to update training materials and train the trainers on the new procedures.

PHMSA estimates that the notification to PSAPs will result in an incremental burden of 2-hours per incident. PHMSA utilizes data from reportable incidents per § 191.5 to estimate the number of instances they believe will prompt immediate notification to PSAPs. However, the proposal expands well beyond reportable incidents and applies to both existing emergencies, such as "gas detected inside or near a building", as well as those mandated by Congress. As proposed natural gas operators would be required to notify PSAPs every time a customer calls concerned about a natural gas leak in a building, even before an operator can confirm if there is a leak present. It is evident that PHMSA either did not intend to apply the new communication aspects to ERP to these types of emergencies or they have not contemplated what burden it would place on natural gas distribution operators.

PHMSA also conflates the general public and customers in its cost-benefit analysis. PHMSA states "distribution operators will incur an additional cost to comply with new communication requirements with customers and the general public. The burden associated with notification to the public will only occur in the event of a gas pipeline emergency." First, PHMSA's proposal addresses communication with the public and customers in two separate sections. Secondly, assuming a burden is only realized after

[21] PHMSA PRIA. Page 24

an emergency has occurred completely negates the burden associated with the development and implementation of a voluntary opt-in notification system for customers. PHMSA assumes that all communication with the public and customers is performed by a public relations specialist. As discussed elsewhere in these comments, PHMSA continues to overestimate in-house resources accessible to a vast majority of the impacted entities by its gas distribution regulations.

The Associations estimate that over two-thirds of natural gas distribution operators in this country do not directly employ communications experts. Therefore, these new requirements will either necessitate the hiring of third-party communications consultants or will be significantly more burdensome for the operators to manage than PHMSA has assumed. PHMSA admits that they have not properly addressed this burden by asking commenters to discuss "the extent to which operators may need to procure or develop new emergency response systems, and the estimated cost of such as system, as well as the burden and labor needs for operators to make notifications to PSAPs, customers, and the public." The Associations were not able to quantify the number of operators that would need to procure an emergency response system nor the cost of those systems in the comment period. But it is imperative for PHMSA to understand this impact before finalizing the rulemaking.

The Associations recommend the following edits to § 192.615:

§ 192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

….

(3) Prompt and effective response to a notice of each type of emergency, including the following:

(i) Gas detected inside or near a building.

(ii) A fire related to an unintended release of gas ~~located near or directly involving a pipeline facility.~~

(iii) Explosion occurring near or directly involving a pipeline facility.

(iv) Natural disaster

(v) Confirmed discovery ~~Notification~~ of potential rupture (see § 192.635).

(vi) Beginning no later than **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE]**, release of gas from a natural gas distribution system that results in one or more fatalities.

(vii) Beginning no later than **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE],** for distribution line operators only, unintentional release of gas ~~and~~ that results in a shutdown of available gas service for more than 24 hours to 270 ~~50~~ or more customers or, if the operator has fewer than 100 customers, 50 percent or more of its total customers.

(viii) ~~Beginning no later than [**ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE],** any other emergency deemed significant by the operator.~~

…

(8) Notifying the appropriate public safety answering point (i.e., 9–1–1 emergency call center) where direct access to a 9–1–1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials, of gas pipeline emergencies to coordinate and share information to determine the location of the emergency, including both planned responses and actual responses during an emergency. The operator must immediately and directly

notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdictions in which the pipeline is located after ~~receiving~~ confirming discovery ~~notice~~ of a gas pipeline emergency under paragraph (a)(3)(ii), (iii), (v), (vi) and (vii). ~~a notification of potential rupture, as defined in § 192.3, to~~ The operator must coordinate and share information to determine the location of any release, regardless of whether the segment is subject to the requirements of § 192.179, § 192.634, or § 192.636.

…

(13) For distribution line operators, beginning no later than **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE]**, identify an appropriate channel to establish~~ing~~ and maintain~~ing~~ communication with the affected ~~general~~ public ~~in the operator's service area~~ as soon as practicable, beginning from the time of confirmed discovery of an ~~during a gas pipeline~~ emergency on a distribution line, as specified in paragraph (a)(3)(ii),(iii), (vi), and (vii). The communication(s) must be in English, and any other languages commonly understood by a significant number ~~and concentration~~ of the non-English speaking population in the operator's service area; ~~be in one or more formats or media accessible to the population in the operator's service area~~; continue through service restoration and recovery efforts; and provide the following:

(i) Information regarding the gas pipeline emergency; and

~~(ii) The status of the emergency (e.g., have the condition causing the emergency or the resulting public safety risks been resolved);~~

~~(iii)~~ Status of pipeline operations affected by the gas pipeline emergency~~, and when possible, a timeline for expected service restoration; and~~

~~(iv) Directions for the public to receive assistance.~~

~~The operator must provide updates when the information in § 192.615(a)(13)(i)-(iv) changes.~~

…

(d) No later than **[INSERT DATE 18 MONTHS AFTER THE PUBLICATION DATE OF THE RULE],** each distribution line operator must develop and implement a system~~, including written procedures,~~ that allows operators to rapidly communicate with affected customers in after the confirmed discovery ~~the event~~ of a gas pipeline emergency ~~under this section,~~ as specified in paragraph (a)(3)(ii),(iii), (vi), and (vii). The notification system must be voluntary, ~~for the public,~~ allowing customers to opt-in ~~(or opt-out)~~ to receiving notifications from the operator ~~system~~. ~~The written procedures must provide for the following:~~

~~(1) A description of the notification system and how it will be used to notify [affected] customers of a gas pipeline emergency;~~

~~(2) Who is responsible for the development, operation, and maintenance of the system;~~

~~(3) How information on the system is delivered to customers, ensuring that all customers are notified of the existence of the system and necessary steps if they wish to opt-in (or opt-out);~~

~~(4) Description of the system-wide testing protocol, including the testing interval (which must not be less than once per calendar year), to ensure the system is functioning properly and performing notifications as designed;~~

~~(5) Maintenance of the results of testing and operations history for at least 5 years;~~

~~(6) Details regarding how the operator ensures messages are accessible in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area;~~

~~(7) Message content, including updates as emergency conditions change;~~

~~(8) A process to initiate, conduct, and complete notifications; and~~

~~(9) Cybersecurity measures to protect the system and customer information.~~

C. *Operations and Maintenance Manuals (Section 192.605)—Overpressurization*

PHMSA proposes (via a new § 192.605(f)) to require operators to update operations and maintenance (O&M) manuals to account for risk of overpressurization events. These updates would require procedural steps to identify and respond to overpressurization indications, including immediately reducing pressure or shutting down portions of the gas distribution system, and the sequence of these specific actions. Updates to O&M manuals would also require steps to investigate, respond to, and correct the cause(s) of overpressurization indications.

While the Associations support amending § 192.605 to address the response to indications of potential overpressurization, it is important to clarify that operators must maintain the operational autonomy to verify these indications and confirm that an overpressure event has actually occurred before taking the considerable step(s) of reducing pressure and/or shutting down portions of the gas distribution system. Indeed, Section 204 of PIPES Act of 2020 stipulates that O&M manual requirements be revised to require written procedures for "responding to overpressurization indications, including specific actions and an order of operations for immediately reducing pressure in or shutting down portions of the gas distribution system, *if necessary*" (emphasis added). However, as-written, PHMSA's proposed amendment to § 192.605 does not include the "if necessary" qualifier, but instead suggests that operators must, in any scenario, reduce pressure or shut down portions of the distribution system immediately upon receiving an overpressurization indication.

Immediately reducing pressure or shutting down portions of the gas distribution system before any investigation of the overpressure indication is problematic for several reasons. First, such actions are likely to interrupt service. The consequence of significant service interruptions is acknowledged in other provisions of this proposed rule (see proposed revisions to § 192.615), and interrupting service unnecessarily may jeopardize public safety during cold-weather conditions, as well as contribute to property damage such as freezing pipes in residences that cannot be accessed during re-lights. Other unique pipeline safety risks associated with shutting down low-pressure distribution systems include the potential for water infiltration in mains and services (as well as the associated freeze-offs) and the service restoration complexities inherent in systems with significant numbers of inside meter sets.

Mandating these specific and immediate steps contradicts the intention of operator-devised O&M manual procedures required by § 192.605, circumvents an operator's duty to investigate and appropriately respond to indications of overpressurization, and contradicts the plain language of Section 204 of PIPES Act of 2020.

The Associations also suggest striking the proposed requirement to prescribe an "order of operations" to the procedures for responding to overpressure indications. Given the myriad scenarios that an operator may face in responding to indications of overpressurization, it is not appropriate to mandate the precise sequence of actions. Describing the specific actions within the procedure – without dictating their precise order in every scenario – is important for preserving the operational flexibility necessary to respond to these indications safely and effectively.

The Associations recommend the following changes to PHMSA's proposed amendments to § 192.605:

§ 192.605 Procedural manual for operations, maintenance, and emergencies.
* * * * *

(f) *Overpressurization.* For distribution lines, the manual required by paragraph (a) of this section must, no later than **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, include procedures for responding to, investigating, and correcting, as soon as practicable, the cause of overpressurization indications. The procedures must include the specific actions ~~and an order of operations~~ for responding to overpressurization indications, and, if necessary, immediately reducing pressure in or shutting down affected portions of the distribution system ~~affected by an overpressurization~~.

D. Operations and Maintenance Manuals (Section 192.605(g))—Management of Change

The Associations recognize Section 204 of the PIPES Act contains a requirement for PHMSA to promulgate a rule requiring a detailed procedure for a Management of Change (MOC) process. The Associations are confident the intent of Congress in requiring an MOC process was to provide controls that would prevent an event similar to the 2018 Merrimack Valley incident. The Associations believe Congress did not intend for PHMSA to impose a requirement for MOC applicable to all gas distribution activities. MOC processes can be complex, challenging to implement, and difficult to manage. It takes years to refine the process, train employees, and change an organization's culture. Congress asked PHMSA to prioritize changes associated with overpressure protection. It is important that PHMSA maintains focus on those activities and assets in promulgating an MOC requirement for gas distribution operators. In addition, PHMSA was mandated to develop a rule requiring O&M manuals from distribution operators to "ensure relevant qualified personnel, such as an engineer with a professional engineer licensure, subject matter expert, or other employee who possesses the necessary knowledge, experience, and skills regarding natural gas systems, review and certify construction plans for accuracy, completeness & correctness."

MOC involves a formal, resource-intensive process and it would be impracticable to try to apply MOC to all gas distribution activities due to the volume of change requests that would need to be submitted and approved. There are countless changes that operators make that never ultimately impact safety. There must be some defined criteria around the highest-risk work activities that warrant utilization of a MOC. The Associations are recommending regulatory text that would reasonably narrow the application of MOC to those activities involved with proper pressure controls and where formal processes should be in place to oversee changes in technology, personnel, equipment or procedures. Use of the word ‘significant’ is necessary to focus where MOC must be applied; this should be determined by the operator. The operator is in the best position to determine what should activate MOC on its system, since it knows best what activities should be reviewed and approved due to the nature of the change involved. This topic is covered in AGA’s 2021 white paper “Natural Gas Utility Guideline for Developing a Management of Change (MOC) Plan for Engineering Design.”

The Associations also offer the following to support its recommended changes to the regulatory requirements associated with MOC:

1. Emergency work must be excluded from the requirement. The urgency required inherently does not allow time for formal review and approvals. There are procedures operators have for emergency response which are predicated on trained (and qualified) personnel taking actions to perform leak investigations, leak repairs, and addressing blowing gas. MOC is an intentional, planned change in design, operation, etc. of a distribution (or transmission) system. Emergency response is an unintentional event requiring immediate action to protect life and property.

2. “Routine” or like-kind replacement work must be excluded from the MOC requirement. A formalized change processes for work that is clearly defined and narrow in scope is unnecessary. Replacing any component with the exact same component is considered “in kind” work and there are several states which have regulations that provide clear exceptions to having such basic maintenance tasks be part of any MOC-type of process. Parts that routinely are replaced “in kind” include springs, boots, and regulators.

3. § 192.631 – *Control room management* (CRM) includes regulatory requirements governing how changes to alarms and pressure monitoring equipment should be managed. The proposed MOC language could be interpreted to apply to alarms and equipment that is already covered by the CRM rule. Operators frequently change alarm set points, to align with the expected pressures of that season. It would be incorrect to assume alarm set points are static and conclude that MOC is necessary. The processes by which these alarm set points are modified are fully outlined in the operator’s CRM and Alarm Management plans. Therefore, it is concerning that these very basic actions would also need to go through MOC, based upon the NPRM.

4. First published in 2001, ASME B31.8S – *Managing System Integrity of Gas Pipelines* was written for operators as a resource to assist in implementing integrity management programs for transmission pipelines. There is no basis for codifying the MOC language in Section 11 of ASME B31.8S into federal regulation for gas distribution pipelines, as it would be a misapplication of that standard. There are fundamental differences that exist between operating distribution pipelines and transmission pipelines.

5. PHMSA has proposed that personnel who approve construction plans must be qualified under Subpart N – Operator Qualification. The Associations strongly urge PHMSA not to include this requirement in the regulation. The skill sets for individuals constructing or working directly on pipeline components can be significantly different than the skills of an individual responsible for reviewing potential changes to those assets. Operator Qualification is intended to test one individual's abilities, skills and knowledge for performing a very specific task. 192.801(b) outlines the four-part test that a task must meet to be considered a *covered task:* (1) Performed on a pipeline facility; (2) is an operations or maintenance task; (3) is performed pursuant to a requirement of this part; and (4) affects the operation or integrity of the pipeline. The task of reviewing potential changes does not meet the four-part test.

6. Approving construction plans clearly does not meet the four-part test. "Construction plans" may or may not involve a design package that comes from Engineering, but the Associations support this terminology, since it justifiably causes the operator to contemplate its intent and the type of work that warrants an evaluation. The Associations understand the basis for this proposed requirement, but urge PHMSA to take caution in specifying when this evaluation must occur, who is authorized to evaluate, and how the evaluation can be affirmed. In summary, the necessary knowledge, experience and competencies are different between approving construction plans and constructing, repairing, or maintaining a pipeline.

7. The Associations believe that § 192.605(g)(2) should only apply on construction plans involving complex work where the risk of system overpressurization exists. Otherwise, this requirement becomes far too burdensome if approvals are required for *any* type of work which may or may not even pose a significant risk of overpressurization. When considering the thousands of different configurations that exist for gas distribution delivery, it would not be feasible to define the activities that might represent complex work. Therefore, operators must have the ability to define what complex work exists on their own system and to be able to identify potential risk factors unique to each project. The associations believe "certify" must mean to show approval with a personal signature or possibly with a stamp, for the professional engineers, where applicable. This would be very similar to authenticating a pressure test with a personal signature. Documented approvals can be made on the construction plans.

Based on the discussion above, the Associations suggest the following changes be made to the proposed regulations regarding MOC for gas distribution pipelines:

§ 192.605 Procedural manual for operations, maintenance, and emergencies.
* * * * *

(g) *Management of Change (MOC) Process.* For distribution pipelines, the manual required by paragraph (a) of this section must, no later than **[INSERT ~~ONE~~ TWO YEARS AFTER THE PUBLICATION DATE OF THE RULE**], include a detailed MOC process for the following:

(1) Significant Technology, equipment, procedural, and organizational changes, including:

(i) Planned Installations, ~~or modifications~~ replacements or abandonments involving physical changes, ~~replacements,~~ ~~or upgrades~~ to pressure regulators ~~on mains and at~~ stations, pressure monitoring locations, or overpressure protection devices on mains;

(ii) ~~Modifications to alarm set points or upper/lower trigger limits on monitoring equipment;~~Permanent changes made to alarm set points or monitoring equipment that are not covered by Subpart L;

(iii) The introduction of new technologies for overpressure protection into the system; and

(iv) Revisions, changes, or the introduction of new standard operating procedures for planned design, construction, installation, and maintenance work, ~~and emergency response~~; where pressure control is impacted

(v) ~~Other changes that may impact the integrity or safety of the gas distribution system.~~ Exceptions to (i), (ii), (iii) and (iv) include the following: routine operating adjustments and like-kind replacements, and any work that does not pose a known risk of overpressurization.

(2) Ensuring that personnel – such as an engineer with a professional engineer license, a subject matter expert, or another person who possesses the necessary knowledge, experience, and ~~skills~~ competencies regarding gas distribution systems – review and certify construction plans associated with complex work involving installations, ~~modifications,~~ replacements, or ~~system upgrades~~ abandonments for accuracy and completeness before the work begins, where the risk of system overpressurization exists. ~~These personnel must be qualified to perform these tasks under subpart N of this part.~~ Personnel certify by providing their signature on the construction plans, or if certified by a professional engineer, a professional engineer stamp.

(3) Ensuring that any hazards introduced by a change are identified, analyzed, and controlled before resuming operations.

E. Gas Distribution Recordkeeping Practices (Section 192.638)

PHMSA also proposes new recordkeeping requirements for distribution system pressure control. The proposal requires operators of distribution systems to "identify and maintain traceable, verifiable, and complete records that document the characteristics of its pipeline system that are critical to ensuring proper pressure control." PHMSA proposes specific information that must be included in those records: location information for regulators, valves, and underground piping; attributes for the regulators (such as set points, design capacity, and valve failure position); the overpressure protection configuration; and other records deemed critical.

Additionally, PHMSA proposes to require an operator to develop and implement procedures to address incomplete traceable, verifiable, and complete (TVC) records. The proposal specifically suggests that operators must address these incomplete records on an "opportunistic basis." The records must be maintained for the life of the pipeline and the operator must ensure the records are "accessible to all personnel responsible for performing or supervising design, construction, operations, and maintenance activities."

This proposal attempts to address one portion of Section 206 of the PIPES Act of 2020. Congress mandated this regulatory action as a result of the NTSB's recommendation to NiSource, Inc. following the explosions and fires on September 13, 2018 in Merrimack Valley, MA. The NTSB recommended that NiSource "review and ensure all records and documentation of your natural gas systems are traceable, reliable, and complete."

The Associations support PHMSA addressing the Congressional mandate and agree that documentation of pressure control equipment plays a critical role in ensuring the safe operation of natural gas distribution systems. The Associations, however, suggest some modifications to the proposed regulatory language to ensure that the goal of efficient and effective improvement of pipeline safety through regulation is realized.

The Associations recommend PHMSA modify how this new requirement is organized to improve clarity.

The Associations have suggested a reorganization of the regulatory requirement that is intended to provide clarity on the requirements. First, the Associations suggest PHMSA specify the information that must be documented for district regulator stations, then PHMSA should outline the expectation for operators to perform a review for available documents, then PHMSA should specify expectations for how operators should fill any gaps in that information. The Associations believe this sets up a better set of regulations for the long term and removes any confusion about compliance timelines.

This reorganization also removes the need for an explicit recordkeeping requirement, as effectively there becomes a requirement to have records for district regulator stations that are currently in service. PHMSA's original proposal to require operators to maintain these documents "for the life of the pipeline" is especially confusing. While PHMSA has broadly defined *pipeline* to include associated appurtenances, operators do not consider regulator stations a pipeline. Furthermore, information prescribed by PHMSA to be included in this documentation is operational and not necessarily static. Suggesting that the documentation should be maintained for the "life of the pipeline" seems to suggest that the information is permanent and unchanging, which is inaccurate.

PHMSA should maintain the standard of "Traceable, Reliable, and Complete" for these records.

As discussed in the DIMP section of these comments, the Associations recommend that PHMSA use the expectation mandated by Congress "traceable, reliable, and complete." The Associations understand PHMSA's desire to use a term already existing in federal regulation, "traceable, verifiable, and complete." The distinction between reliable and verifiable is important and deliberate, especially in the context of this recordkeeping requirement. Some operators may choose to generate a singular document containing all the information prescribed by PHMSA. The information contained in that document may be traceable, reliable, and complete. Other operators may choose to compile several documents meeting that same requirement. The term "verifiable" does not allow for this flexibility.

PHMSA's proposal reaches beyond pressure control records and needs to be clarified.

The Associations also offer recommendations to clarify the information that must be contained in these records. The intent of this provision is to ensure that information that relates to a potential overpressurization event is contained within the record. All other information is unnecessary and potentially diverting from the intent to capture relevant information for protection against overpressurization events.

1. PHMSA should be specific on the types of regulators, valves, and piping that must be included in the record.
2. Instead of listing regulator setpoints, valve failure positions, and the design capacity as example attributes of a station, PHMSA should specify their inclusion in the record. If PHMSA determines that additional attributes associated with district regulator stations should be included in the record, PHMSA should specify those in the regulatory requirement. Utilizing an open-ended list is unclear and can lead to regulatory confusion.
3. PHMSA should refrain from including "other records deemed critical" from a list of mandatory records. As mentioned above, leaving these lists open ended is confusing for both the operator and the regulator attempting to verify compliance.

Not all personnel need to see all records associated with pressure control.

Congress mandated that operators "ensure that records … are accessible to all personnel responsible for overseeing relevant construction and engineering work." PHMSA expanded this requirement to "an operator must ensure the records required by this section are accessible to all personnel responsible for performing or supervising design, construction, operations, and maintenance activities."

Not all records associated with district regulator stations need to be accessible to all employees at all times. The Associations agree with PHMSA's intent: ensuring employees have access to records they need to perform their job, prevent accidental overpressurization, and keeping the pipeline system safe. However, allowing open access to all these records is not in the interest of pipeline safety and security. The Associations have recommended several qualifying edits, below, to the proposed rule's records access provisions for PHMSA's consideration to better ensure that operators have the ability to put necessary safeguards in place for these records.

PHMSA has failed to consider the interplay between this new provision and the proposed provision for Management of Change processes for changes impacting pressure control. The Associations encourage PHMSA to contemplate whether it may enhance pipeline safety to require the implementation of MOC per proposed § 192.605(b) prior to requiring operators to implement procedures to opportunistically address incomplete records. The Associations are recommending a two-year implementation timeframe for the development of MOC for significant technology, equipment, procedural and organizational changes for changes impacting overpressure protection.

The compliance timelines recommended below for § 192.638 are independent of the MOC proposals and our comments on that section. However, the Associations believe it is worth contemplating whether they should be further extended to allow the MOC process to be in place prior to implementing procedures to fill record gaps.

PHMSA fails to address any benefits associated with this provision and has vastly underestimated the costs to comply.

PHMSA does not address this provision in the benefits discussion of the PRIA. The Associations understand that the introduction of § 192.638 into regulation is aligned with a Congressional mandate, but there is still a statutory requirement for PHMSA to conduct a risk assessment that "identifies the costs and benefits associated with the proposed standard"[22].

In estimating the costs of this provision, PHMSA identifies three actions associated with this proposal: (1) reviewing the rule and its requirements (2) performing record gathering, and (3) addressing incomplete records. PHMSA estimates those three activities to be performed in the following timeframes:

1. Review Rule & Requirements = 8 hours
2. Record Gathering
    a. Stations installed after 1990 = 8 hours/station
    b. Stations installed before 1990 = 16 hours/station
3. Addressing Incomplete Records = 1 hour/station

PHMSA has applied an hourly rate for an engineer to all these estimates to calculate the cost of this proposal, effectively assuming it will be a single engineer spending one to two days to address this proposal. PHMSA has failed to account for the wide variety of individuals that will need to take part in the review of records and then coordinating the new system of record: engineering, construction, operations & maintenance, measurement & regulation, instrumentation & control, gas control, and mapping. One operator with several hundred district regulator stations assumes it will take close to 200

[22] 49 U.S.C. § 60102 – Purpose and General Authority

hours per station for this review to be performed to ensure traceability, reliability, and completeness of the records.

Below are the Associations' suggested edits to §192.638:

§ 192.638 Distribution lines: Records for pressure controls.

(a) ~~An~~ Operators of distribution systems, except those identified in paragraph (f), must ~~no later than [INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], identify and~~ maintain traceable, reliable ~~verifiable~~, and complete records ~~that document the characteristics of its pipeline system that are~~ critical to ensuring proper pressure control at district regulator stations. These records must include:

(1) ~~Current~~ Location information (including maps and schematics) for district regulators, isolation and station bypass valves, and underground station and control piping (including control lines);

(2) District regulator set point ranges;

(3) Regulator or control valve failure positions (open/closed);

(4) The design capacity of the district regulator station; and

(5) ~~Attributes of the regulator(s), such as set points, design capacity, and the valve failure position (open/closed);~~

(6) The overpressure protection configuration~~; and~~.

~~(7) Other records deemed critical.~~

(b) ~~If an operator does not have traceable, verifiable, and complete records as required by paragraph (a) of this section, the~~ Operators must, no later than [INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], identify and retain available ~~and document those~~ records required by paragraph (a). ~~needed and develop and implement procedures for collecting those records.~~

(c) If an operator does not have records required by paragraph (a), no later than [INSERT EIGHTEEN MONTHS AFTER THE PUBLICATION DATE OF THE RULE] the operator must develop and begin implementing procedures for collecting those records ~~The records identified in paragraph (a) of this section must be collected, generated, or updated~~ on an opportunistic basis, ~~as specified in~~ consistent with § 192.1007(a)(3).

(d) An operator must ensure the relevant pressure control records, as ~~required~~ defined by this section and appropriate for the job being performed, are accessible ~~made available~~ to ~~all~~ personnel responsible for performing or supervising design, construction, operations, and maintenance activities.

(e) ~~An operator must retain the records required in paragraph (a) of this section for the life of the pipeline.~~

(f) Exception. This section does not apply to master meter systems, liquefied petroleum gas (LPG) distribution pipeline systems that serve fewer than 100 customers from a single source, or any individual service line directly connected to a transmission, gathering, or production pipeline that is not operated as part of a distribution system.

F. *Distribution Pipelines: Presence of Qualified Personnel (Section 192.640)*

The Associations are generally supportive of the regulatory requirements in 192.640 and activities that are intended to mitigate the possibility of an accident similar to the tragedy in Merrimack Valley in 2018. However, there are two clarifications that should be made to ensure the regulatory requirement is interpreted consistently:

- *Construction projects performed by the operator trigger evaluation, not those performed by third parties.* The proposed requirement to perform an evaluation of construction projects performed in the vicinity of a district regulator station is only for projects being performed by or on behalf of the operator. This requirement should not apply to construction work being performed by third-party construction crews or excavators. Projects performed by a public works crew, a telecommunications provider, or other utility requires 811 notification. That notification then triggers an entirely different series of actions depending on the nature of the excavation and its proximity to natural gas infrastructure.

- *The evaluation that is required should be on a main construction project **in the vicinity of a district regulator station**.* Without this added specificity, thousands of construction project evaluations would be required annually for a large distribution operator, with negligible benefits in public safety. The distance of the project from a regulator station is intentionally left open-ended, because the distance necessitating an evaluation will vary based on a variety of factors that are unique to the district regulator station, including its geographic location. Operators are in the best position to determine the proximity of a main project which should invoke the requirements in § 192.640 and will surely take a conservative approach to maintain safety.

The Associations recommend the following changes to PHMSA's proposed regulatory text for § 192.640:

§ 192.640 Distribution lines: Presence of qualified personnel.

(a) An operator of a distribution system must conduct a documented evaluation of each operator's gas main construction project in the vicinity of a district regulator station that begins after [INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE] to identify any potential operator project activities during which an overpressurization could occur at a district regulator station. This evaluation must occur before such activities begin. Activities that may present a potential for overpressurization include, but are not limited to, tie-ins, and abandonment of distribution lines~~, and equipment replacement.~~

(b) If the evaluation in paragraph (a) of this section results in a determination that a potential for overpressurization exists during construction project activity, the operator must:

(1) Ensure that at least one person qualified according to subpart N of this part is present at that district regulator station, or at an alternative site, during the construction project activity that could cause an overpressurization;

(2) Monitor gas pressure with equipment capable of ~~ensuring~~ observing proper pressure controls; and

(3) Have the capability to promptly shut off the flow of gas or control ~~overpressurization~~ pressure at a district regulator station or at an alternative site.

(c) When monitoring the system as described in this section, the qualified personnel must be provided, at a minimum: information regarding the location of all valves necessary for isolating the pipeline system; pressure control records (see § 192.638); the authority to stop work (unless prohibited by operator procedures); operations procedures under § 192.605; and emergency response procedures under § 192.615.

(d) Exception. Distribution systems with a remote monitoring system in effect with the capability for remote or automatic shutoff need not comply with the requirements in paragraphs (a) through (c) of this section.

G. District Regulator Stations—Protections Against Accidental Overpressurization (Sections 192.195, 192.741, and 192.1007(d)(2)(ii))

PHMSA proposes to amend § 192.195 to require operators to equip all new, replaced, relocated, or otherwise changed district regulator stations serving low-pressure gas distribution systems with at least two methods of overpressure protection. PHMSA similarly proposes to amend § 192.1007(d)(2)(ii) to require operators to ensure two methods of overpressure protection are present – consistent with proposed amendments § 192.195 – at all *existing* district regulator stations, or to identify (along with notification to PHMSA) alternative preventive and mitigative measures to minimize risk of overpressurization at these existing stations.

Additionally, PHMSA proposes to require operators to design such district regulator stations to minimize risk from an overpressurization of a low-pressure system caused by a single event (e.g., excavation damage, natural forces, equipment failure, or incorrect operations) that either immediately or over time affects the safe operation of more than one overpressure protection device. PHMSA furthermore proposes an amendment to § 192.741 that would require operators to provide monitoring of the outlet gas pressure at or near district regulator stations serving low-pressure systems (whenever these stations are new, replaced, relocated, or otherwise changed) using a device capable of real-time notification to the operator of overpressurization.

1) PHMSA must carefully define the applicability of provisions intended to protect against overpressurization of low-pressure systems.

The Associations are concerned about applying the proposed amendments to § 192.195 and § 192.741 to district regulator stations and low-pressure distribution systems that are "otherwise changed," given the fact that many projects that could meet the definition of "otherwise changed" – even those involving significant alterations to the district regulator station – will not have any impact whatsoever on the functionality of the station with regards to pressure control and monitoring. Changes involving alterations and reconfigurations of station facilities such as heater and odorizers should not be subject to design considerations specific to pressure control and monitoring. Moreover, PHMSA's proposed amendments to § 192.1007 already ensure that existing district regulator stations serving low-pressure distribution systems will be considered for, and/or retrofitted with, 2nd-level overpressure protection (or alternative preventive and mitigative measures to minimize risk of overpressurization). Consequently, the requirements proposed for § 192.195(c) should only be applied to new, replaced, or relocated district regulator stations serving low-pressure distribution systems.

The Associations are also concerned with PHMSA's proposal to require two "methods" of overpressure protection to be present for any new, replaced, or relocated district regulator station serving low-pressure distribution systems, as per § 192.195(c). PHMSA already proposes in § 192.195(c) that an operator take "measures to minimize the risk of overpressurization of the low-pressure distribution system that could be caused by any single event…that…affects the safe operation of more than one overpressure protection device." An operator may find it appropriate to prescribe the same method of overpressure protection for 2nd-level protection (e.g., "super-monitor" regulation), and this flexibility should be allowed as long as the operator has considered (and taken steps to eliminate) the single mode of failure for overpressure protection devices. The Associations instead recommend revising the proposed regulatory text to require at least two *means* of overpressure protection.

Additionally, while the Associations support PHMSA's proposal to require monitoring of pressure at or near district regulator station overpressure protection devices (as per § 192.195(c)(3)), Section 206 of PIPES Act of 2020 does not mandate that this pressure monitoring be performed remotely. Importantly, this proposal should not nullify the exemptions to CRM requirements as defined in § 192.631(a)(1)(i). This exemption ensures that procedures for CRM, as defined by § 192.631, are not required for operators of small gas distribution systems (< 250,000 services). It is important to ensure that monitoring of a low-pressure distribution system does not undo this exemption, by virtue of the fact that "part of a pipeline facility" is being "monitored…through a SCADA system." Therefore, the Associations propose that gas distribution systems that meet the exemption for CRM procedures (as defined in § 192.631(a)(1)(i)) also be exempt from the requirement that pressure monitoring be performed remotely.

Finally, PHMSA's proposal to revise § 192.741 to require pressure monitoring (in accordance with § 192.195(c)) on "low-pressure distribution systems that are new, replaced, relocated, or otherwise changed" is superfluous to § 192.195(c) itself. In the exceedingly unlikely event that a gas distribution pipeline operator would install a *new* low-pressure distribution system, entirely replace such a system with *another* low-pressure system, or relocate a low-pressure system in its entirety, the operator would almost certainly build, replace, or relocate the district regulator station(s) feeding that system, thus ensuring that pressure monitoring would be provided as per § 192.195(c). In contrast, "otherwise changing" a low-pressure distribution system (as opposed to the district regulator station that serves it) whereby the system *remains* low-pressure, might occur at such a frequency, and (as stated previously) with such irrelevance to controlling the pressure of the system, that mandating the installation of pressure monitoring for every such project would be both onerous and of limited safety benefit. In any case, § 192.195(c) already fulfills the mandate of Section 206 of PIPES Act of 2020, which requires that "each operator of a distribution system [assess] and [upgrade], as appropriate, each district regulator station of the operator to ensure that….the gas pressure of a low-pressure distribution system is monitored, particularly at or near the location of critical pressure-control equipment." While the Associations recognize the potential risk of replacing a low-pressure distribution system with a new, higher-pressure distribution system (as was the case for the Merrimack Valley incident), those particular risks are addressed and controlled for in the other provisions of this NPRM. In conclusion, the Associations assert that the newly proposed § 192.741(d) be struck.

2) PHMSA must allow for implementation of alternative measures to minimize risk of overpressurization.

While measures such as installation of 2nd-level overpressure protection and monitoring of gas pressure may be effective in providing additional protection against overpressurization of low-pressure gas distribution systems, it is critical to recognize that alternative measures can provide equivalent levels of protection against overpressurization. The Associations appreciate PHMSA's recognition of the potential effectiveness of these alternative measures in their proposed requirement to evaluate and/or upgrade existing district regulator stations (see § 192.1007(d)(2)(ii)(B)). However, these alternatives should also be available for new, replaced, and relocated district regulator stations serving low-pressure distribution systems. Indeed, Section 206 of PIPES Act of 2020 requires that district regulator stations be "assess[ed] and upgrad[ed], as appropriate," and furthermore that alternative "actions…that minimize the risk of an overpressurization event" may be identified by an operator if the more prescriptive requirements (proposed in § 192.195(c)) are not operationally possible.

With this in mind, operators should be given flexibility to identify alternative measures for minimizing the risk of overpressurization on new, replaced, and relocated district regulator stations serving low-pressure distribution systems. Preserving this flexibility in § 192.195 would allow and encourage implementation of technologies such as remotely-controlled shutoff valves, system relief valves, automated detection of damaged/compromised pressure controls lines (i.e., putting pressure regulation and overpressure protection into passive operation), meter technology with overpressure protection and excess flow functionality, individual service regulators or slam-shut devices at customer delivery points, and other state-of-the-art technologies. Low-pressure operators have already been evaluating these technologies and implemented some since the Merrimack Valley incident.

3) The timeline for upgrading existing District Regulator Stations (or identifying alternative measures) must be appropriately considered to mitigate the risk of overpressurization.

PHMSA's PRIA estimates 10,199 district regulator stations servicing low-pressure distribution systems[23], of which PHMSA estimates that 40% already have "at least two methods" of overpressure protection[24]. Both of these figures vastly underestimate the number of district regulator stations serving low-pressure distribution currently outfitted with two levels of overpressure protection. Respondents to a survey of 24 operators conducted by AGA in October 2023 operated a minimum of zero, maximum of 2,200, and average of 346 district regulator stations serving low-pressure distribution systems. A linear regression model (based on total miles of distribution main and total services operated) of this survey data indicates there are approximately 57,250 district regulator stations serving low-pressure distribution systems nationwide, nearly six times higher than PHMSA's estimate. Moreover, the surveyed operators indicated that approximately 12% of these stations are equipped with 2nd-level overpressure protection. Therefore, PHMSA *underestimates* the number of district regulator stations requiring upgrade as per the proposed § 192.1007(d)(2)(ii) by a factor of *eight* (6,119[25] stations versus 50,265).

PHMSA also significantly underestimates the cost to upgrade existing district regulator stations with 2nd-level overpressure protection under § 192.1007(d)(2)(ii). PHMSA's PRIA estimates the cost to upgrade each station to be $7,500 (the purported cost of installing one slam-shut device)[26]. Installation of a single slam-shut will not be appropriate for all (or even most) district regulator stations, and in many cases the district regulator station may not have the required space to retrofit with 2nd-level overpressure protection, thus requiring replacement or relocation of the station. The aforementioned survey of 24 AGA member operators estimated the associated per-station upgrade cost to in fact be somewhere between $50,000 (median) and $176,000 (mean), with the station rebuild scenario costing as much as $2 million. PHMSA's PRIA also neglects to consider the additional O&M costs associated with annual inspecting and testing 2nd-level overpressure protection as per §§ 192.739 and 192.743. One AGA member operator estimates approximately $130 in inspection and testing costs per overpressure protection device. Across the more than 50,000 estimated district regulation stations serving low-pressure distribution systems nationwide, this translates to an annual O&M cost of roughly $6.5 million, over and above what operators are already spending to inspect and test overpressure protection devices.

[23] PRIA at 18.
[24] PRIA at 22.
[25] PRIA at 22.
[26] PRIA at 22.

Operators also anticipate absorbing additional costs associated with training and qualifying operations personnel to install, inspect, and/or test the supplemental overpressure protection devices required by this rulemaking. All told, this orders-of-magnitude cost difference reflects a significant miscalculation by PHMSA in the time and scope required to upgrade the affected district regulator stations, and will necessarily have substantial impacts to the time required for operators to reasonably fund and complete this work.

Beyond the considerable underestimation of the effort required to address the relevant systems and stations, PHMSA acknowledges within this NPRM that work on facilities involving pressure control and overpressure protection devices poses a unique and inherent risk, requiring – among other things – MOC (§ 192.605), on-site presence of qualified personnel (§§ 192.605 and 192.640), implementation of ERPs (§ 192.615), and record collection (§ 192.638).

Initiating such work therefore introduces risk of the very overpressurization events that this NPRM seeks to prevent and mitigate. This is particularly concerning when this work is being proposed on an unprecedented scale (tens of thousands of district regulator stations serving low-pressure distribution systems) and either concurrently with, or more probably *prior to*, completing implementation of the enhanced MOC, personnel qualification, ERPs, and record collection procedures proposed in this rulemaking. Compressing this work into one year (less than one year, given seasonal and permitting constraints) is a further risk multiplier, and a significant one at that. In short, the requirements and timeline proposed by PHMSA in § 192.1007(d)(2)(ii) is not only unlikely to decrease the risk of overpressurization of low-pressure distribution systems, it stands to significantly *increase* this risk.

Moreover, while the Associations acknowledge the unique characteristics of worker-monitor regulator configurations and the need to address the particular risk of overpressurization of low-pressure distribution systems protected by such district regulator stations, PHMSA has failed to demonstrate that district regulator stations currently outfitted with full-capacity pressure relief devices or slam-shut devices carries a similar risk profile. In addition to the 2018 Merrimack Valley incident, PHMSA mentions two comparable overpressurization incidents in the proposed rule: a 1982 incident in Centralia, Missouri[27] and a 1977 incident in El Paso, Texas[28]. As at Merrimack Valley, both of these incidents involved below-grade sense lines, and would not have occurred if protection against system overpressurization had been provided by pressure relief or slam-shut devices. Indeed, following the Merrimack Valley incident, PHMSA recommended operators consider installation of a full-capacity relief valve downstream of the low-pressure regulator station, or installation of a slam-shut device, as a means of "protect[ing] low-pressure distribution systems from overpressure events" (ADB-2020-02 – Overpressure Protection on Low-Pressure Natural Gas Distribution Systems)[29]. Operators have already been designing and/or upgrading district regulator stations with the PHMSA advisory bulletin in mind, and there is no evidence to suggest that a single

[27] FR at 61787.
[28] FR at 61788.
[29] FR at 61101.

full-capacity pressure relief device or slam-shut provides inadequate overpressure protection.

For these reasons, the Associations contend that while a one-year timeline (from the publication of the rule) is reasonable for confirming and documenting the status of overpressure protection and pressure monitoring at each existing district regulator station serving low-pressure distribution systems, the minimum timeline for upgrading or identifying alternative measures for mitigating risk of overpressurization should be not less than *ten years* from the date from the publication of the rule, but not less than *fifteen* years for stations already outfitted with a full-capacity relief device or slam-shut device. A fifteen-year minimum effective date would: (1) allow operators to effectively implement the aforementioned risk-mitigation measures described in the other provisions of this NPRM, (2) allow for prudent and intentional implementation of alternative measures for mitigating risk of overpressurization for those stations not meeting the requirements of § 192.195(c), (3) acknowledge seasonal and permitting constraints that (for some operators) stands to significantly limit the window for performing upgrades, and (4) allow operators time to execute existing plans to retire or abandon low-pressure distribution systems in concert with their asset management strategy, and as already approved by their public utility commissions. .

As stated previously in these comments, the Associations are also opposed to the insertion of design standards from § 192.195(c) into the DIMP rule, in contravention of the nonapplication clause (49 U.S.C. § 60104(b)). While specifying the identification of "alternative measures" to protect against overpressurization of low-pressure systems may be appropriate, it is inappropriate to insert explicit requirements into the DIMP rule to upgrade existing district regulator stations to meet the requirements proposed in § 192.195(c). To address this issue, the Associations propose that § 192.1007(d)(2)(ii) be written to require the aforementioned "alternative measures" for those district regulator stations that are confirmed to not meet the requirements of § 192.195(c). Operators may exempt themselves from identifying and implementing these "alternative measures" if they upgrade, replace, relocate (or retire) the station to meet the requirements of § 192.195(c) within the ten-year compliance timeline the Associations propose for § 192.1007(d)(2)(ii).

Furthermore, the Associations propose to eliminate the requirement to notify PHMSA and State or local pipeline safety authorities of these alternative measures (as per § 192.18(c)) in light of PHMSA's considerable underestimation of the number of district regulator stations serving low-pressure distribution systems.

Accordingly, the Associations recommend the following changes to PHMSA's proposed amendments to §§ 192.195, 192.741, and 192.1007:

§ 192.195 Protection against accidental overpressuring.

* * * * *

(c) *Additional requirements for low-pressure distribution systems.* Each regulator station that is new, replaced, or relocated after [**INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, and which serves ~~serving~~ a low-pressure distribution system, ~~that is new, replaced, relocated, or otherwise changed **after [INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**~~ must ~~include~~ either:

(1) Include each of the following:

(i) At least two means ~~methods~~ of overpressure protection (such as, but not limited to, a relief valve, monitoring regulator, or automatic shutoff valve) appropriate for the configuration and siting of the station;

~~(2)~~(ii) Measures to minimize the risk of overpressurization of the low-pressure distribution system that could be caused by any single event (such as excavation damage, natural forces, equipment failure, or incorrect operations), that either immediately or over time affects the safe operation of more than one overpressure protection device; and

~~(3)~~(iii) ~~Remote m~~Monitoring of gas pressure at or near the location of overpressure protection devices. Remote monitoring is required unless the operator is exempted from control room management requirements as per § 192.631(a)(1)(i).

Or,

(2) Identify alternative measures based on the unique characteristics of its system to minimize the risk of overpressurization of a low-pressure distribution system.

§ 192.741 Pressure limiting and regulating stations: Telemetering, ~~or~~ recording gauges, and other monitoring devices.

* * * * *

~~(d) On low-pressure distribution systems that are new, replaced, relocated, or otherwise changed after **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, the operator must monitor the gas pressure in accordance with § 192.195(c)(3).~~

§ 192.1007 What are the required elements of an integrity management plan?

* * * * *

(d) *Identify and implement measures to address risks.*

* * * * *

(2) *Minimization of Overpressurization of Low-Pressure Distribution Systems.*

* * * * *

(ii) Confirm and document that each district regulator station serving a low-pressure distribution system meets the requirements of § 192.195(c)(1) through (3) by **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**. If an operator determines that a district regulator station serving a low-pressure distribution system does not meet the requirements of § 192.195(c)(1) through (3), then the operator must take alternative measures based on the unique characteristics of its system to minimize the risk of overpressurization of a low-pressure distribution system. The operator must take these alternative measures no later than:

(A) **[INSERT FIFTEEN YEARS AFTER THE PUBLICATION DATE OF THE RULE]** for any district regulator station serving a low-pressure distribution system with a full-capacity pressure relief device or slam-shut device not otherwise meeting the requirements of § 192.195(c)(1) through (3), or

(B) **[INSERT TEN YEARS AFTER THE PUBLICATION DATE OF THE RULE]** for all other district regulator stations serving a low-pressure distribution system not otherwise meeting the requirements of § 192.195(c)(1) through (3).

~~by **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, the operator must take either of the following actions:~~

~~(A) Upgrade the district regulator station to meet the requirements of § 192.195(c)(1) through (3), or~~

~~(B) Identify alternative preventive and mitigative measures based on the unique characteristics of its system to minimize the risk of overpressurization of a low-pressure distribution system. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of implementing any alternative measures. The notification must be made in accordance with § 192.18(c) and must include a description of proposed alternative measures, identification and location of facilities to which the measures would be applied, and a description of how the measures would ensure the safety of the public, affected facilities, and environment.~~

H. Inspection: General (Section 192.305)

In its 2015 "Miscellaneous Changes to Pipeline Safety" rulemaking[30] PHMSA modified § 192.305 to address a 2002 National Association of Pipeline Safety Representatives (NAPSR) Petition for Rulemaking. That NAPSR petition requested that PHMSA amend the regulation to "prohibit a contractor that is hired to do construction work for an operator from inspecting its own work."[31] After the final rule, both NAPSR and APGA filed petitions for clarification or reconsideration. APGA requested that PHMSA clarify that PHMSA was "not intending to require third party inspections or attempting to prohibit any person from a company to inspect the work of another person from the same company".[32] NAPSR petitioned PHMSA to reconsider the amendment to § 192.305 and revise it to address their concerns, specifically allowing contract personnel to inspect the work of their crews if the inspector did not directly perform the task being inspected, appears to apply to operator construction personnel as well, and significantly limits the scope of inspection requirements by limiting required construction inspections of mains and transmission lines

[30] Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations. Final Rule. 80 Fed. Reg. 12,762. https://www.federalregister.gov/documents/2015/03/11/2015-04440/pipeline-safety-miscellaneous-changes-to-pipeline-safety-regulations

[31] NAPSR Central Region Resolution. Resolution CR-1-02. May 9, 2022. [INSERT LINK]

[32] 80 Fed. Reg. at 12764

to only requirements found in Subpart G, rather than in all of Part 192.[33] On September 30, 2015 PHMSA issued a response to the NAPSR and APGA petitions and delayed the effective date of the amended § 192.305 indefinitely.

In this NPRM, PHMSA proposes to address the APGA Petition for Reconsideration by adding § 192.305(b), which allows operator personnel involved in the same construction task on distribution mains to inspect each other's work "in situations where the operator could otherwise only comply with the construction inspection requirement … by using a third-party inspector." APGA thanks PHMSA for trying to address their petition for reconsideration and believes the addition of § 192.305(b) addresses their concern and is aligned with PHMSA's original position that they did not intend to require third party inspections.

The Associations support the intent of § 192.305 - ensuring pipelines are constructed according to an operator's construction standards and procedures. The Associations agree that oversight of construction activities is a critical element of an operator's pipeline safety program.

The Associations request that PHMSA address all the questions and confusion that resulted from their first introduction of this provision, before seeking to implement this new requirement.

The Associations strongly recommend a stay-of-enforcement remain in effect until all outstanding questions and requests for clarification from 2015 are resolved. As proposed in this rule, the regulatory text continues to be confusing and is ripe for misinterpretation. During this comment period, the Associations contemplated multiple variations of regulatory text so as to provide PHMSA with a counterproposal. However, the Associations decided not to recommend edits to PHMSA's proposed § 192.305. The Associations believe it is imperative that final regulatory text language be developed in collaboration with all impacted stakeholder groups: the public, federal and state regulators, transmission, distribution, and gathering line operators of all sizes, and the contractor community.

Regulatory uncertainty remains on the Construction Inspection provision and additional clarity is needed to prevent inconsistent enforcement from federal and state regulators.

The Associations, however, remain concerned about the implementation of 192.305 and the lack of clarity concerning how operators will document compliance. In 2015, PHMSA convened a working group that was collaborating on Frequently Asked Questions pertaining to this provision.[34] The Associations encourage PHMSA to continue the work of that group to provide regulatory certainty on this provision. The questions contemplated by the PHMSA Task Group in 2015 that remain unresolved include:

1. What is the scope of § 192.305?
2. If an individual who is an employee of the operator performs a construction task that has a required inspection, can the same individual perform the required inspection?

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[33] NAPSR Request for Delay in the Effective Date of Amended Rule 192.305 on Construction Inspection. July 28, 2015. http://nebula.wsimg.com/6271e37a42898591c6e5c0d4b3a72fa5?AccessKeyId=8C483A6DA79FB79FC7FA&disposition=0&alloworigin=1]

[34] See Attachment.

3. If an individual who is an employee of a contractor conducts a construction task that has a required inspection, can the same individual perform the required inspection?
4. For construction tasks requiring an inspection, does the individual performing the inspection have to observe the entire procedure associated with the task?
5. What is included as persons? Does the rule apply to both contractors and company employees performing construction tasks? Does a definition of person also include a team or crew?
6. Can individuals working on the same team or crew inspect each other's work?
7. Must each component be inspected or can the operator utilize a risk-based methodology to insure that construction defects are minimized?
8. What construction tasks should be given higher priority for inspection?
9. What documentation is required to substantiate that an item or construction task has been adequately completed and inspected?
10. How long should an operator maintain the inspection records required by this section?
11. What are the requirements to determine if an inspector is sufficiently qualified?
12. Inspection is defined as the act of looking at something closely in order to learn more about it, to find problems, etc. Are various technologies (e.g. jeeping, geometry tool, in line inspection devices, radiography, magnetic particle, ultra-sonic, etc.) considered to be forms of inspections?
13. Which components of mains and transmission lines are to be inspected during construction?

Other questions that remain include:

- What is a construction task and what tasks require inspection?
- Does every iteration of that task need to be inspected?
- What does it mean to be involved in a construction task?

Since first promulgated in 2015, there has been significant technological advancements to aid operators in performing construction inspections. Consideration of those advancements needs to be accounted for in PHMSA's proposed requirements.

Since 2015, there has been significant technological advancement in collaboration tools. PHMSA should account for this in newly proposed regulatory text. Absent a specific allowance for remote inspection, operators may be prohibited from utilizing this important technology. Furthermore, as outlined in the questions above, PHMSA should specify if remote inspection through technology is required to be instantaneous viewing of the construction task being performed, or if video recordings of this work is permitted to be reviewed at a later time.

PHMSA has failed – both in its initial proposal in 2013 to amend § 192.305, as well as the current NPRM – to contemplate the new recordkeeping requirements this provision would effectively mandate.

49 CFR Part 192 - Subpart G has only 2 explicit recordkeeping requirements (coating repairs & alternative MAOP). Operators are not currently required to document the individuals performing various construction tasks. This provision would not only require operators to note the individual performing an inspection, but also would require the operators to document the individual performing each iteration of a construction task

performed per Subpart G. That is onerous, burdensome, and has not been addressed by PHMSA.

PHMSA has also failed to directly address the record retention requirement for these inspection activities. With an extreme interpretation of the existing proposed language, the recordkeeping activities to prove compliance would result in a tremendous amount of documentation. PHMSA has failed to account for the data storage complexities that would arise from some interpretations of the proposal.

PHMSA's estimates for the costs to comply are incomplete and inaccurate.

PHMSA concludes that large natural gas distribution operators and all transmission and gathering operators "would be able to comply with § 192.305(a) without hiring additional, new personnel, as a result of their large number employees and established inspection procedures and best practices." PHMSA assumes that all operators will only require two hours of engineer's time to comply with PHMSA's proposed construction inspection requirements.

This estimation validates the Associations position that PHMSA does not appreciate the magnitude of regulatory uncertainty that persists concerning this provision. An extreme interpretation of this provision could suggest that every construction task would always require two individuals: one to perform the work and one to observe and inspect the work being done. No pipeline operator has this redundancy in their workforce.

Workforce challenges plague the pipeline industry, just as it does all skilled labor industries. Suggesting that operators have this flexibility shows either a gross misunderstanding by PHMSA about the workforce operating the nation's pipeline system or the actual expectations surrounding this provision. PHMSA also has not provided a realistic estimation of time (in hours) required to comply with this provision. In either case, PHMSA needs to provide clarity on what inspections are required and revise their PRIA to reflect reality.

PHMSA's proposal leaves a one-year gap in the regulatory requirement to provide Construction Inspection.

PHMSA's proposal indicates that the new inspection requirements would go into effect one year after the publication of the final rule. To maintain a construction inspection requirement for the interim year, PHMSA should retain the existing requirement in code. The Associations recommend PHMSA maintain the existing code language as § 192.305(a) and add new subsections for any future new requirements that may go into effect at a date after the effective date of the final rule.

PHMSA also uses the term "or otherwise changed" in three different sections of this proposed rule. In the section of these comments discussing *District Regulator Stations – Protecting Against Accidental Overpressurization*, the Associations discuss why this language is superfluous and duplicative of "replaced or relocated". The Associations recommend PHMSA strike that terminology from the regulation.

Separate and distinct documentation justifying the use of an exception allowed in a regulation is not necessary.

In PHMSA's newly proposed 192.305(b), PHMSA includes a requirement for documented justification whenever an operator utilizes personnel involved in a construction task to forego the need to hire a third-party inspector. The Associations contend that a specific documentation requirement for justification is superfluous and unnecessary. Operators are always required to document how they meet a regulatory requirement. There is no need for a specific documented justification for utilizing a piece of pipeline safety regulation.

At this time, the Associations are recommending PHMSA <u>maintain</u> the existing language for § 192.305:

§ 192.305 Inspection: General.

(a) Each transmission line or main must be inspected to ensure that it is constructed in accordance with this part.
(b) ~~Each transmission pipeline and main that is new, replaced, relocated, or otherwise changed after **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]** must be inspected to ensure that it is constructed in accordance with this subpart. Except as provided in paragraph (b), an operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operator personnel who are involved in other construction tasks.~~
(c) ~~For the construction inspection of a main that is new, replaced, relocated, or otherwise changed after **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE],** operator personnel involved in the same construction task may inspect each other's work in situations where the operator could otherwise only comply with the construction inspection requirement in paragraph (a) of this section by using a third-party inspector. This justification must be documented and retained for the life of the pipeline.~~

I. Records: Tests (Sections 192.517 and 192.725)

PHMSA proposes to modify § 192.517(b) to add prescription concerning the attributes of the test record that must be maintained and require test records to be retained for the life of the pipeline. This proposal is in response to a 2021 NAPSR Resolution. NAPSR requested that PHMSA (1) modify 49 CFR § 192.517(b) to require that documentation be retained for the life of the pipeline, including test pressure documentation created within the five years prior to the effective date of the rule change and (2) additionally modify § 192.517(b) to require specific test attributes. PHMSA also proposes to modify § 192.725 – *Test requirements for reinstating service lines* to align the record retention requirement with the proposal for § 192.517(b).

The Associations recognize the importance of retaining information related to test records on distribution systems and support some modifications to the record retention requirements. However, the Associations recommend PHMSA narrow the required information to be retained in the record to three critical pieces of information: (1) the date the test was performed, (2) the test pressure, (3) and notation of what pipe segment was tested. Absent specific justification from PHMSA, the additional information included in proposed § 192.517(b)(2) is not supported for inclusion by the Associations.

PHMSA fails to justify the inclusion of this provision in the proposed rule.

PHMSA states in the PRIA that they believe “improving the quality and availability of these records could improve the effectiveness of investigations into the causes of incidents and help inform best practices to prevent incidents into the future.”[35] However, PHMSA fails to point to a single reportable pipeline incident associated with inadequate or inaccessible test records on service lines, plastic pipelines, or pipelines operating less than 100 psig. The Associations evaluated PHMSA reportable incidents on natural gas pipeline systems and failed to identify a single incident related to inadequate pressure tests on these pipelines.

The Plastic Pipeline Database Committee (PPDC)[36] reviews and reports on failures within plastic pipeline systems across the United States. Experience from within the PPDC shows that failures due to installation error typically happen within the first 5 years, and later life failures are typically due to material degradation. This shows that any failures due to improper pressure testing would be expected to happen early in the life of the pipeline, and keeping records for the life of the pipeline only increases administrative costs and does little to improve safety.

PHMSA then states that it is “unable to quantify the effect the proposal rule will have on reducing the frequency and severity of incidents and is unable to calculate fully the potential safety and environmental benefits.”[37] Absent demonstration of a benefit that this proposal will have on pipeline safety and the lack of Congressional mandate to modify the regulatory requirement, PHMSA has failed to meet their statutory obligation - to conduct a risk assessment that “identifies the costs and benefits associated with the proposed standard.”[38]

It is worth noting that PHMSA also oddly estimates the mileage of new distribution lines, new Type A, B, and C gathering lines, and new transmission pipelines to extrapolate a burden estimate for this proposal. The proposed changes to § 192.517(b) only apply to plastic pipelines, non-plastic pipelines operating below 100 psig, and service lines. The inclusion of Type A and C gathering lines and transmission pipelines is largely irrelevant to this proposal, as it almost exclusively applies to gas distribution pipelines.

In PHMSA’s PRIA they “assume that operators would incur a negligible burden to update their procedures to retain the documentation for these tests for the life of the pipeline, instead of five years.”[39] While the simple act of updating the procedures may not be substantial, it is far from the only activity that occurs when there is a change to recordkeeping requirements. Individuals performing the tests must receive updated training to ensure they understand what is required in the documentation, written or digital forms used to capture the information must be updated, and employees responsible for maintaining record retention policies must be made aware of the change. Additionally, and

[35] PRIA at 54.
[36] The Plastic Pipe Database Committee (PPDC) is a group of representatives of federal and state regulatory agencies and the natural gas and plastic pipe industries. The goal is to create a national database of information related to the in-service performance of plastic piping materials. https://www.aga.org/natural-gas/safety/promoting-safety/plastic-pipe-data-collection-initiative/
[37] PRIA at 54
[38] 49 U.S.C. § 60102 – Purpose and General Authority
[39] PRIA at 38.

as discussed elsewhere in these comments and throughout the Associations comments to PHMSA's Leak Detection and Repair rulemaking, the default record retention policy for most gas distribution records is 10-years. This aligns with the record retention requirements in DIMP, § 192.1011.[40] While some operators have chosen to maintain records for the life of the asset, others have chosen to utilize a 10-year record retention policy. Therefore, PHMSA must address the cost associated with the regulatory change and cannot assume it to be negligible.

PHMSA then estimates how much the new record requirement will cost operators during the performance of the leak tests. PHMSA assumes an additional burden of 2-hours per test and that leak tests on new lines occur in 5-mile segments. This assumption alone exposes the lack of understanding concerning how distribution pipelines are constructed. A vast majority of the leak pressure tests subject to this new record requirement are on service lines. The average service line, per PHMSA's Gas Distribution Annual Report F-7100.1, is approximately 71 feet, 23 yards, or approximately 0.01 miles. Using PHMSA's estimate of 16,320 miles of new distribution pipe installed annually that would need to meet the proposed recordkeeping requirements, the Associations believe the number of leak pressure tests is likely much closer to 1.2 million - not 3,246 as PHMSA estimated.

Leak pressure test and strength pressure tests are not synonymous and their role in the safe operations of pipelines differ.

NAPSR's 2021 petition for rulemaking points to PHMSA's record retention requirements for pressure test records in § 192.517(a) as justification for additional requirements in § 192.517(b). § 192.517(a) specifies recordkeeping for the various testing requirements of steel pipelines, §§ 192.505, 192.506, and 192.507. §§ 192.505 and 192.506 both detail strength testing requirements for transmission lines and higher-pressure distribution steel pipelines. § 192.505 is intended to substantiate the proposed MAOP of a new pipeline, and §192.506 is intended to evaluate additional threats on a new or existing pipeline, where the operator deems it to be necessary. §192.507 is also intended for non-plastic pipelines operating at pressures at or above 100 PSI, but with the intended purpose to discover leaks.

In contrast, § 192.517(b) specifies recordkeeping requirements tests on low to medium pressure pipelines, service lines, and plastic pipelines. The purpose of these tests is to identify all potentially hazardous leaks in the segment being tested prior to installation. This testing is consistent with recommendations under ASME B31.8, which also explicitly differentiates between pressure testing of distribution pipelines and service lines to discover leaks versus strength testing of transmission and high pressure distribution lines to discover and repair various potential defects on those higher risk pipeline segments. Furthermore, The Plastic Pipelines Institute (PPI) states that, "Leak tests of pressure systems generally involve filling the system or a section of the system with a liquid or gaseous fluid and applying internal pressure to determine resistance to leakage."[41] Resistance to leakage is separate and different from verification of the strength of the pipe

[40] 192.1001 What records must an operator keep? – An operator must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of superseded integrity management plans developed under this subpart.

[41] https://www.plasticpipe.org/MunicipalAdvisoryBoard/MunicipalAdvisoryBoard/Navigation/Connection-Menu/Pressure-Testing.aspx#:~:text=Leak%20tests%20of%20pressure%20systems,to%20determine%20resistance%20to%20leakage.

material. In fact, every time a natural gas distribution operator performs a leak survey on a pipeline system (per § 192.723), the operator is effectively performing a new leak test.

While the Associations support clarification of the recordkeeping requirements for §§ 192.509, 192.511, and 192.513, retaining leak test records should align with current DIMP record retention requirements, which is 10 years.

Information included in the test record should align with the information needed for verification for the safe operation of the pipeline.

As discussed above, leak tests are performed on low or medium pressure pipelines at the time of construction to verify no hazardous leaks exist on the pipeline when the pipeline is put into service. Therefore, the only information necessary for the test record is the segment being tested, when it was tested, and the test pressure. The Associations disagree with the inclusion of the following attributes of the test:

1. *Operator's name, etc.* – This identification information is not used in the verification of a natural gas system's operator pressure. PHMSA has failed to justify why it should be included in the proposed rule and provides no benefits for its inclusion in the PRIA. Therefore, the associations recommend that it be removed from the proposal.
2. *Test duration* - Minimum test durations are not mandated by 192.509, 192.511, 192.513. Test duration should not be recorded if there is no mandated minimum duration that needs to be met.
3. *Leaks and failures noted and their disposition*- When performing leak tests per §§ 192.509, 192.511, 192.513, or 192.725 and a leak is identified in the test segment, operators will discontinue the test and address the leak. Once the leak has been addressed, a new test is initiated. Therefore, any leak that may have existed on the test segment is no longer present and not associated with the final leak test. For this reason, the Associations recommend that PHMSA remove § 192.517(b)(2)(vii).
4. *Test medium used* – The regulations that govern the Maximum Allowable Operating Pressure (MAOP) for steel pipelines operating below 100 psig, plastic pipelines, and service lines only reference the pressure utilized during the test. These MAOP establishment regulations do not discuss the test medium and therefore this information is unnecessary to achieve NAPSR's goals of ensuring pipelines in operation meet the general provision found in 192.603 that "each operator shall keep records necessary to administer the procedures under 192.605".[42]

PHMSA's proposed revisions to 192.517(b) are confusing and could be easily misinterpreted.

PHMSA proposed regulatory changes include a modification to 192.517(b) to state that all test records are to be maintained for the "life of the pipe". This is confusing and is ripe for misunderstanding in the future. The Associations suggest revisions to 192.517 for the three different scenarios under consideration:

[42] NAPSR 2021 Petition. "Whereas PHMSA has set forth regulations in 49 CFR 192.603(b) requiring operators to keep records necessary to administer procedures established under 49 CFR 192.605, which includes 192.619 and 192.725."

1. Tests that occurred more than five years prior to the publication of a final rule.
2. Tests that occurred within five years prior to the publication of the final rule.
3. Tests that occur on or after the publication of the final rule.

The Associations recommend the following changes to the test record proposal:

§ 192.517 Records.
* * * * *

(b) Each operator must maintain a record of each test required by §§ 192.509, 192.511, and 192.513. ~~for at least five years~~ ~~the life of the pipeline.~~
   (1) For tests performed before [INSERT FIVE YEARS PRIOR TO THE PUBLICATION DATE OF THE FINAL RULE] the record must be retained for at least five years.
   (2) For tests performed after [INSERT FIVE YEARS PRIOR TO THE PUBLICATION OF THE FINAL RULE], but before [INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE] ~~for which records are maintained~~, the test record must ~~continue to~~ be ~~maintained~~ retained for ~~the life of the pipeline~~ at least 10 years.
   (3) For tests performed on or after [INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], the records must be retained for at least 10 years and must contain at least the following information:
      ~~(i) The operator's name, the name of the employee responsible for making the test, and the name of the company or contractor used to perform the test.~~
      (ii) Pipeline segment pressure tested.
      (iii) Test date.
      ~~(iv) Test medium used.~~
      (v) Test pressure.
      ~~(vi) Test duration.~~
      ~~(vii) Leaks and failures noted and their disposition.~~

§ 192.725 Test requirements for reinstating service lines.

(a) Except as provided in paragraph (b) of this section, each disconnected service line being restored to service on or after [INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE] must be tested in the same manner as a new service line (I.E., tested in accordance with subpart J of this part), before being ~~reinstated~~ restored to service.

(b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

J. *Amendments to Gas Distribution System Annual Report*

PHMSA also proposed to amend the Gas Distribution System Annual Report (PHMSA F 7100.1-1) in order to "collect additional information, such as the number and miles of low-pressure service lines, including their overpressure protection methods."[43]

The Associations believe that the revisions to the annual report proposed by PHMSA could introduce confusion for operators. Firstly, the "Worker Regulator" listed in the table of "Methods of Overpressure Protection" (Part B, Question 6) should be revised to say "Monitor Regulator." Worker regulators serve as the primary means of pressure control, the potential failure of which must be accounted for with an overpressure protection device (e.g., monitor regulators) as described in § 192.195(a). Secondly, slam-shut devices should be listed in the same table, unless PHMSA considers them to be "automatic shutoff valves," in which case this should be clearly described in the instructions for form PHMSA F 7100.1-1. Thirdly, Part B, Question 6 should be revised to report "means" of overpressure protection rather than "methods" (see previous discussion).

Finally, PHMSA should be aware that the relationship between the number of low-pressure systems (Part B, Question 5) and the means of overpressure protection of those systems (Part B, Question 6) is widely variable. Some low-pressure systems are fed by a single district regulator station, while other low-pressure systems are fed by many such stations. Therefore, PHMSA should not expect anything like a 1:1 relationship between primary overpressure protection and low-pressure systems.

III. PHMSA Solicitation of Comments

In the NPRM, PHMSA solicits information and feedback on several topics associated with the proposed requirements. As discussed previously, PHMSA cannot propose topics generally and meet its obligations under the APA. Stakeholders must be given an opportunity to comment. Furthermore, it is unreasonable for PHMSA to expect detailed responses on so many questions when commenters are unable to ascertain how PHMSA will use this information, particularly with there being minimal context provided. The Associations believe these types of questions are more appropriate to be asked in an Advance Notice of Proposed Rulemaking (ANPRM) where the agency is clearly in the preliminary stages of its rulemaking efforts. The Associations have chosen to devote its time to providing meaningful and credible comments on the proposed regulatory language, rather than answering a dozen questions on how ICS works and what ICS training entails. As mentioned previously, this simply demonstrates the need for PHMSA to connect with those organizations representing public first responders and FEMA, and to coordinate a public meeting that can explore these kinds of issues. Without a public meeting, PHMSA is instead left contemplating how ICS could benefit emergency response to pipeline accidents, and it is inappropriate for the agency to promulgate requirements on operators without first being educated on what it takes to implement ICS. PHMSA is encouraged to

[43] FR at 61750.

connect with the National Association of State Fire Marshals to learn more about emergency response to pipeline accidents, and what practices can truly improve response.

IV. Summary of Suggested Edits to Proposed Code-Language

Below is a compilation of the Associations' suggested edits to the proposed code language contained in the NPRM:

§ 192.195 Protection against accidental overpressuring.

* * * * *

(c) *Additional requirements for low-pressure distribution systems.* Each regulator station that is new, replaced, or relocated after **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, and which serves ~~serving~~ a low-pressure distribution system, ~~that is new, replaced, relocated, or otherwise changed **after [INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**~~ must ~~include~~ either:

(1) Include each of the following:

(i) At least two means ~~methods~~ of overpressure protection (such as, but not limited to, a relief valve, monitoring regulator, or automatic shutoff valve) appropriate for the configuration and siting of the station;

~~(2)~~(ii) Measures to minimize the risk of overpressurization of the low-pressure distribution system that could be caused by any single event (such as excavation damage, natural forces, equipment failure, or incorrect operations), that either immediately or over time affects the safe operation of more than one overpressure protection device; and

~~(3)~~(iii) ~~Remote m~~Monitoring of gas pressure at or near the location of overpressure protection devices. Remote monitoring is required unless the operator is exempted from control room management requirements as per § 192.631(a)(1)(i).

Or,

(2) Identify alternative measures based on the unique characteristics of its system to minimize the risk of overpressurization of a low-pressure distribution system.

§ 192.305 Inspection: General.

(a) Each transmission line or main must be inspected to ensure that it is constructed in accordance with this part.

(b) ~~Each transmission pipeline and main that is new, replaced, relocated, or otherwise changed after **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]** must be inspected to ensure that it is constructed in accordance with this subpart. Except as provided in paragraph (b), an operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the~~

~~operator from inspecting construction tasks with operator personnel who are involved in other construction tasks.~~

(c) ~~For the construction inspection of a main that is new, replaced, relocated, or otherwise changed after **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE],** operator personnel involved in the same construction task may inspect each other's work in situations where the operator could otherwise only comply with the construction inspection requirement in paragraph (a) of this section by using a third-party inspector. This justification must be documented and retained for the life of the pipeline.~~

§ 192.517 Records.

* * * * *

(b) Each operator must maintain a record of each test required by §§ 192.509, 192.511, and 192.513. ~~for~~ at least five years ~~the life of the pipeline.~~

(1) For tests performed before [INSERT FIVE YEARS PRIOR TO THE PUBLICATION DATE OF THE FINAL RULE] the record must be retained for at least five years.

(2) For tests performed after [INSERT FIVE YEARS PRIOR TO THE PUBLICATION OF THE FINAL RULE], but before [INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE] ~~for which records are maintained~~, the test record must ~~continue to~~ be ~~maintained~~ retained for ~~the life of the pipeline~~ at least 10 years.

(3) For tests performed on or after [INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], the records must be retained for at least 10 years and must contain at least the following information:

~~(i) The operator's name, the name of the employee responsible for making the test, and the name of the company or contractor used to perform the test.~~

(ii) Pipeline segment pressure tested.

(iii) Test date.

~~(iv) Test medium used.~~

(v) Test pressure.

~~(vi) Test duration.~~

~~(vii) Leaks and failures noted and their disposition.~~

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

* * * * *

(f) *Overpressurization.* For distribution lines, the manual required by paragraph (a) of this section must, no later than **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, include procedures for responding to, investigating, and correcting, as soon as practicable, the cause of overpressurization indications. The procedures must include the specific actions ~~and an order of operations~~ for responding to overpressurization indications, and, if necessary, immediately reducing pressure in or shutting down affected portions of the distribution system ~~affected by an overpressurization~~.

(g) *Management of Change (MOC) Process.* For distribution pipelines, the manual required by paragraph (a) of this section must, no later than **[INSERT ~~ONE~~ TWO YEARS AFTER THE PUBLICATION DATE OF THE RULE]**, include a detailed MOC process for the following:

(1) Significant Technology, equipment, procedural, and organizational changes, including:

(i) Planned Installations, ~~or modifications~~ replacements or abandonments involving physical changes, ~~replacements,~~ ~~or upgrades~~ to pressure regulators ~~on mains and at~~ stations, pressure monitoring locations, or overpressure protection devices on mains;

(ii) ~~Modifications to alarm set points or upper/lower trigger limits on monitoring equipment;~~Permanent changes made to alarm set points or monitoring equipment that are not covered by Subpart L;

(iii) The introduction of new technologies for overpressure protection into the system; and

(iv) Revisions, changes, or the introduction of new standard operating procedures for planned design, construction, installation, and maintenance work, ~~and emergency response~~; where pressure control is impacted

(v) ~~Other changes that may impact the integrity or safety of the gas distribution system.~~ Exceptions to (i), (ii), (iii) and (iv) include the following: routine operating adjustments and like-kind replacements, and any work that does not pose a known risk of overpressurization.

(2) Ensuring that personnel – such as an engineer with a professional engineer license, a subject matter expert, or another person who possesses the necessary knowledge, experience, and ~~skills~~ competencies regarding gas distribution systems – review and certify construction plans associated with complex work involving installations, ~~modifications,~~ replacements, or ~~system upgrades~~ abandonments for accuracy and completeness before the work begins, where the risk of system overpressurization exists. ~~These personnel must be qualified to perform these tasks under subpart N of this part.~~ Personnel certify by providing their signature on the construction plans, or if certified by a professional engineer, a professional engineer stamp.

(3) Ensuring that any hazards introduced by a change are identified, analyzed, and controlled before resuming operations.

§ 192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

….

(3) Prompt and effective response to a notice of each type of emergency, including the following:

(i) Gas detected inside or near a building.

(ii) A fire related to an unintended release of gas ~~located near or directly involving a pipeline facility.~~

(iii) Explosion occurring near or directly involving a pipeline facility.
(iv) Natural disaster
(v) Confirmed discovery ~~Notification~~ of potential rupture (see § 192.635).
(vi) Beginning no later than **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE]**, release of gas from a natural gas distribution system that results in one or more fatalities.
(vii) Beginning no later than **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE],** for distribution line operators only, unintentional release of gas ~~and~~ that results in a shutdown of available gas service for more than 24 hours to 270 ~~50~~ or more customers or, if the operator has fewer than 100 customers, 50 percent or more of its total customers.
(viii) ~~Beginning no later than [**ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE],** any other emergency deemed significant by the operator.~~

…

(8) Notifying the appropriate public safety answering point (i.e., 9–1–1 emergency call center) where direct access to a 9–1–1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials, of gas pipeline emergencies to coordinate and share information to determine the location of the emergency, including both planned responses and actual responses during an emergency. The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdictions in which the pipeline is located after ~~receiving~~ confirming discovery ~~notice~~ of a gas pipeline emergency under paragraph (a)(3)(ii), (iii), (v), (vi) and (vii).~~a notification of potential rupture, as defined in § 192.3, to~~ The operator must coordinate and share information to determine the location of any release, regardless of whether the segment is subject to the requirements of § 192.179, § 192.634, or § 192.636.

…

(13) For distribution line operators, beginning no later than **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE]**, identify an appropriate channel to establish~~ing~~ and maintain~~ing~~ communication with the affected ~~general~~ public ~~in the operator's service area~~ as soon as practicable, beginning from the time of confirmed discovery of an ~~during a gas pipeline~~ emergency on a distribution line, as specified in paragraph (a)(3)(ii),(iii), (vi), and (vii). The communication(s) must be in English, and any other languages commonly understood by a significant number ~~and concentration~~ of the non-English speaking population in the operator's service area; ~~be in one or more formats or media accessible to the population in the operator's service area~~; continue through service restoration and recovery efforts; and provide the following:
(i) Information regarding the gas pipeline emergency; and
~~(ii) The status of the emergency (e.g., have the condition causing the emergency or the resulting public safety risks been resolved);~~
~~(iii)~~ Status of pipeline operations affected by the gas pipeline emergency~~, and when possible, a timeline for expected service restoration; and~~
~~(iv) Directions for the public to receive assistance.~~

~~The operator must provide updates when the information in § 192.615(a)(13)(i)-(iv) changes.~~

…

(d) No later than **[INSERT DATE 18 MONTHS AFTER THE PUBLICATION DATE OF THE RULE],** each distribution line operator must develop and implement a system~~, including written procedures,~~ that allows operators to rapidly communicate with affected customers in after the confirmed discovery ~~the event~~ of a gas pipeline emergency ~~under this section,~~ as specified in paragraph (a)(3)(ii),(iii), (vi), and (vii). The notification system must be voluntary, ~~for the public,~~ allowing customers to opt-in ~~(or opt-out)~~ to receiving notifications from the operator ~~system~~. ~~The written procedures must provide for the following:~~

~~(1) A description of the notification system and how it will be used to notify [affected] customers of a gas pipeline emergency;~~

~~(2) Who is responsible for the development, operation, and maintenance of the system;~~

~~(3) How information on the system is delivered to customers, ensuring that all customers are notified of the existence of the system and necessary steps if they wish to opt-in (or opt-out);~~

~~(4) Description of the system-wide testing protocol, including the testing interval (which must not be less than once per calendar year), to ensure the system is functioning properly and performing notifications as designed;~~

~~(5) Maintenance of the results of testing and operations history for at least 5 years;~~

~~(6) Details regarding how the operator ensures messages are accessible in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area;~~

~~(7) Message content, including updates as emergency conditions change;~~

~~(8) A process to initiate, conduct, and complete notifications; and~~

~~(9) Cybersecurity measures to protect the system and customer information.~~

§ 192.638 Distribution lines: Records for pressure controls.

(a) ~~An~~ Operators of distribution systems, except those identified in paragraph (f), must ~~no later than [INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], identify and~~ maintain traceable, reliable ~~verifiable~~, and complete records ~~that document the characteristics of its pipeline system that are~~ critical to ensuring proper pressure control at district regulator stations. These records must include:

(1) ~~Current~~ Location information (including maps and schematics) for district regulators, isolation and station bypass valves, and underground station and control piping (including control lines);

(2) District regulator set point ranges;

(3) Regulator or control valve failure positions (open/closed);

(4) The design capacity of the district regulator station; and

(5) ~~Attributes of the regulator(s), such as set points, design capacity, and the valve failure position (open/closed);~~

(6) The overpressure protection configuration~~; and~~.

~~(7) Other records deemed critical.~~

(b) ~~If an operator does not have traceable, verifiable, and complete records as required by paragraph (a) of this section, the~~ Operators must, no later than **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, identify and retain available ~~and document those~~ records required by paragraph (a). ~~needed and develop and implement procedures for collecting those records.~~

(c) If an operator does not have records required by paragraph (a), no later than [INSERT EIGHTEEN MONTHS AFTER THE PUBLICATION DATE OF THE RULE] the operator must develop and begin implementing procedures for collecting those records ~~The records identified in paragraph (a) of this section must~~

~~be collected, generated, or updated~~ on an opportunistic basis, ~~as specified in~~ consistent with § 192.1007(a)(3).

(d) An operator must ensure the relevant pressure control records, as ~~required~~ defined by this section and appropriate for the job being performed, are accessible ~~made available~~ to ~~all~~ personnel responsible for performing or supervising design, construction, operations, and maintenance activities.

(e) ~~An operator must retain the records required in paragraph (a) of this section for the life of the pipeline.~~

(f) Exception. This section does not apply to master meter systems, liquefied petroleum gas (LPG) distribution pipeline systems that serve fewer than 100 customers from a single source, or any individual service line directly connected to a transmission, gathering, or production pipeline that is not operated as part of a distribution system.

§ 192.640 Distribution lines: Presence of qualified personnel.

(a) An operator of a distribution system must conduct a documented evaluation of each operator's gas main construction project in the vicinity of a district regulator station that begins after **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]** to identify any potential operator project activities during which an overpressurization could occur at a district regulator station. This evaluation must occur before such activities begin. Activities that may present a potential for overpressurization include, but are not limited to, tie-ins, and abandonment of distribution lines~~, and equipment replacement.~~

(b) If the evaluation in paragraph (a) of this section results in a determination that a potential for overpressurization exists during construction project activity, the operator must:

(1) Ensure that at least one person qualified according to subpart N of this part is present at that district regulator station, or at an alternative site, during the construction project activity that could cause an overpressurization;

(2) Monitor gas pressure with equipment capable of ~~ensuring~~ observing proper pressure controls; and

(3) Have the capability to promptly shut off the flow of gas or control ~~overpressurization~~ pressure at a district regulator station or at an alternative site.

(c) When monitoring the system as described in this section, the qualified personnel must be provided, at a minimum: information regarding the location of all valves necessary for isolating the pipeline system; pressure control records (see § 192.638); the authority to stop work (unless prohibited by operator procedures); operations procedures under § 192.605; and emergency response procedures under § 192.615.

(d) Exception. Distribution systems with a remote monitoring system in effect with the capability for remote or automatic shutoff need not comply with the requirements in paragraphs (a) through (c) of this section.

§ 192.725 Test requirements for reinstating service lines.

(a) Except as provided in paragraph (b) of this section, each disconnected service line being restored to service on or after **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]** must be tested in the same manner as a new service line (I.E., tested in accordance with subpart J of this part), before being ~~reinstated~~ restored to service.

(b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

§ 192.741 Pressure limiting and regulating stations: Telemetering, ~~or~~ recording gauges, and other monitoring devices.

* * * * *

~~(d) On low-pressure distribution systems that are new, replaced, relocated, or otherwise changed after **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, the operator must monitor the gas pressure in accordance with § 192.195(c)(3).~~

§ 192.1007 What are the required elements of an integrity management plan?

* * * * *

(a) * * *

(3) Identify additional information and provide a plan for gaining that information over time ~~(including the records specified in § 192.638l)~~ through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

* * * * *

(b) Identify threats. The operator must consider the following categories of threats to each gas distribution pipeline: c~~C~~orrosion (including atmospheric corrosion);~~,~~ natural forces (~~including~~ such as extreme weather, land movement, ~~and~~ or other geological hazards)~~,~~; excavation damage, other outside force damage, material (including the presence ~~and age~~ of ~~pipes such as~~ cast iron~~, bare steel, unprotected steel, wrought iron, and historic plastics with known issues~~) or welds;~~,~~ equipment failure;~~,~~ incorrect operations;~~,~~ ~~overpressurization of low-pressure distribution systems;~~ and other ~~issues~~ threats that ~~could threaten~~pose a risk to the integrity of ~~its~~ a pipeline. An operator must also consider the age of the system, pipe, and components in

identifying threats. An operator must consider reasonably available information when attempting to ~~consider~~identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records (including atmospheric corrosion records), continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

(c) Evaluate and rank risk.

(1) *General.* An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.

(2) *Certain pipe with known issues.* An operator must, no later than **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, evaluate the risks in the distribution system resulting from pipelines with known issues based on the material (including, cast iron~~, bare steel, unprotected steel, wrought iron, and historic plastics with known issues~~), design, ~~age~~ vintage, or past operating and maintenance history.

(3) *Low-pressure Distribution Systems*. An operator must, no later **than [INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, evaluate the risks that could lead to or result in ~~from the operation~~ overpressurization of a low-pressure distribution system ~~at a pressure that makes the operation of any connected and properly adjusted low-pressure gas burning equipment unsafe~~. In the evaluation of risks, an operator must:

(i) Evaluate factors other than past observed abnormal operating conditions (as defined in § 192.803) in ranking risks, including any known industry threats, risks, or hazards to public safety that could occur on its system based on knowledge gained from available sources;

(ii) Evaluate potential consequences associated with applicable low-probability events that could result in an overpressurization of a low-pressure distribution system unless a determination, supported and documented by an engineering analysis, or an equivalent analysis incorporating operational knowledge, demonstrates that the event results in no significant~~potential~~ consequences~~, and therefore no potential risk. An operator must notify PHMSA and State or local pipeline safety authorities, as applicable, in accordance with § 192.18 within 30 days of making such a determination. The notification must include the following:~~

~~(A) Date the determination was made;~~

~~(B) Description of the low-probability event being considered;~~

~~(C) Logic Justification supporting the determination, including information from an engineering analysis, or an equivalent analysis incorporating operational knowledge;~~

~~(D) Description of any preventive and mitigative measures actions taken, including any measures considered but not taken;~~

~~(E) Details of the low-pressure system applicable to the event that results in no potential consequence and risk, including, at a minimum, the miles of pipe, number of customers, number of district regulators supplying the system, and other relevant information; and~~

~~(F) Written statement summarizing the documentation provided in the notification.~~

(iii) Evaluation of the configuration of ~~primary and any secondary~~ overpressure protection installed at district regulator stations (such as a relief valves, monitoring regulators, or automatic shutoff valves), the availability of gas pressure monitoring at or near overpressure protection equipment, and the likelihood of any single event (such as excavation damage, natural forces, equipment failure, or incorrect operations), that ~~either immediately or over time,~~ could result in an overpressurization of the low-pressure distribution system.

* * * * *

(d) Identify and implement measures to address risks.

(1) *General.* ~~Determine~~ An operator must identify and implement, as appropriate, measures ~~designed~~ to reduce the risks ~~from~~ of failure of its ~~gas~~ distribution pipeline system, consistent with the evaluation required by § 192.1007. ~~The measures identified and implemented must address, at a minimum, risks associated with the age of pipeline components, the overall age of the system and components, the presence of pipes with known issues, and overpressurization of low-pressure distribution systems.~~ These measures must include an effective leak management program (unless all leaks are repaired when found).

(2) *Minimization of Overpressurization of Low-Pressure Distribution Systems.* An operator must, no later than **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, implement the following ~~preventive and mitigative~~ measures to minimize the risk of overpressurization of a low-pressure distribution system that could be the result of any single event or failure:

~~(i) Identify, maintain, and obtain, if necessary, pressure control records in accordance with §§ 192.638 and 192.1007(a)(3).~~

~~(ii)~~ Confirm and document that each district regulator station serving a low-pressure distribution system meets the requirements of § 192.195(c)(1) through (3) by **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**. If an operator determines that a district regulator station serving a low-pressure distribution system does not meet the requirements of § 192.195(c)(1) through (3), then the operator must take alternative measures based on the unique characteristics of its system to minimize the risk of overpressurization of a low-pressure distribution system. The operator must take these alternative measures no later than:

(A) **[INSERT FIFTEEN YEARS AFTER THE PUBLICATION DATE OF THE RULE]** for any district regulator station serving a low-pressure distribution system with a full-capacity pressure relief device or slam-shut device not otherwise meeting the requirements of § 192.195(c)(1) through (3), or

(B) **[INSERT TEN YEARS AFTER THE PUBLICATION DATE OF THE RULE]** for all other district regulator stations serving a low-pressure distribution system not otherwise meeting the requirements of § 192.195(c)(1) through (3).

~~by **[INSERT ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE]**, the operator must take either of the following actions:~~

~~(A) Upgrade the district regulator station to meet the requirements of § 192.195(c)(1) through (3), or~~

~~(B) Identify alternative preventive and mitigative measures based on the unique characteristics of its system to minimize the risk of overpressurization of a low-pressure distribution system. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of implementing any alternative measures. The notification must be made in accordance with § 192.18(c) and must include a description of proposed alternative measures, identification and location of facilities to which the measures would be applied, and a description of how the measures would ensure the safety of the public, affected facilities, and environment.~~

V. Conclusion

The Associations support addressing Congressional mandates from the Leonel Rondon Pipeline Safety Act in the PIPES Act of 2020. Industry is committed to learning from pipeline incidents and modifying their practices, policies, and procedures to prevent future similar incidents. Industry demonstrated that commitment immediately following the 2018 tragedy in Merrimack Valley, Massachusetts. From implementing MOC processes, to reviewing overpressure protection configurations, to mapping of underground sensing lines at district regulator stations, industry has not stood idle. The Associations share the goal of maintaining pipeline safety with PHMSA and appreciate the role PHMSA plays in supporting it.

The Associations believe it is also PHMSA's role to understand the current state of play for our country's pipeline operators. This rulemaking follows just months after PHMSA's proposed LDAR Rule. That extensive rulemaking appears to be on an aggressive timeline for completion and its requirements will impact every aspect of daily operations of natural gas distribution pipeline systems. While each of these proposed rules will ultimately be promulgated separately, PHMSA should evaluate the collective impact these two rules will have on the entities they are responsible for regulating, particularly natural gas distribution operators.

As a society we commonly understand that "when everything is a priority, then nothing is a priority." PHMSA should carefully consider whether the inclusion of certain proposals within the NPRM enhance safety or simply increase the compliance burden of operating a pipeline system. Furthermore, there are several provisions within this rulemaking that either wholly or partially are not mandated by Congress. The burden of compliance must enhance safety and should not simply be a transfer of responsibility from the regulator to the operator. Nearly two-thirds of the entities impacted by this rule are considered small businesses, as they are gas utilities employing less than 100 individuals. Those small systems meet every safety standard PHMSA imposes on natural gas distribution operators. PHMSA must ensure that this proposed rule – and any proposed rule – advances the safety of the natural gas distribution system without imposing inefficient, impractical, and needlessly burdensome requirements on operators who are working every day to safely provide a critically important source of energy to millions of Americans.

The Associations are confident that through this rulemaking process, practicable and reasonable regulations will be promulgated, and we thank PHMSA for the opportunity to participate in the process.

Respectfully submitted
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Christina Sames, *Senior Vice President, Safety, Operations, Engineering, and Security*
American Gas Association
400 North Capitol Street, NW
Washington, D.C. 20001
(202) 824-7214
csames@aga.org

Alan Chichester, *Director, Safety, Operations, and Engineering*
American Gas Association
400 North Capitol Street, NW
Washington, D.C. 20001
(202) 824-7328
achichester@aga.org

Erin Kurilla, *Vice President, Operations and Safety*
American Public Gas Association
201 Massachusetts Avenue, NE
Washington, D.C. 20002
(202) 905-2904
ekurilla@apga.org

Jose Costa, *President & CEO*
Northeast Gas Association
1800 West Park Drive, Suite 340
Westborough, MA 01581
(202) 279-1664
jcosta@northeastgas.org