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

Pipeline Safety: Gas Pipeline Leak Detection and Repair	Docket Nos. PHMSA-2023-0061 PHMSA-2024-0005 RIN: 2137-AF51

COMMENTS ON
PIPELINE SAFETY: MEETING OF THE GAS PIPELINE ADVISORY COMMITTEE
(GAS PIPELINE LEAK DETECTION AND REPAIR RULE)

FILED BY
AMERICAN GAS ASSOCIATION
AMERICAN PETROLEUM INSTITUTE
AMERICAN FUEL & PETROCHEMICAL MANUFACTURERS
AMERICAN PUBLIC GAS ASSOCIATION
GPA MIDSTREAM ASSOCIATION
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
NORTHEAST GAS ASSOCIATION

April 29, 2024

Table of Contents

I. Introduction

The American Gas Association (AGA)[1], American Public Gas Association (APGA)[2], Interstate Natural Gas Association of America (INGAA)[3], American Petroleum Institute (API)[4], GPA Midstream[5], Northeast Gas Association (NGA)[6], and American Fuel & Petrochemical Manufacturers (AFPM)[7] (jointly "the Associations") submit these comments[8] for consideration by the Pipeline and Hazardous Materials Safety Administration (PHMSA or the Agency) concerning the Gas Pipeline Advisory Committee (GPAC or the Committee) meetings held to review and discuss PHMSA's proposed rule, "Gas Pipeline Leak Detection and Repair" (NPRM)[9], as well as the Agency's associated regulatory analyses (including, but not limited to, the cost-benefit and risk assessment analyses within the NPRM and the regulatory impact analyses; the environmental assessments; and other materials pertaining to the NPRM provided in the public docket for this rulemaking[10].

PHMSA held an initial GPAC meeting in Arlington, VA from November 27 to December 1, 2023.[11] Due to the complexity, expansive scope, and significant potential impacts of PHMSA's proposed requirements on regulated entities, state regulators, and consumers, as well as the time

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[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] INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 27 members, representing the vast majority of the U.S. interstate natural gas transmission pipeline companies. INGAA's members operate nearly 200,000 miles of pipelines and serve as an indispensable link between natural gas producers and consumers.

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

[5] Shaping the U.S. midstream energy sector since 1921, GPA Midstream sets standards for natural gas liquids; develops simple and reproducible test methods to define the industry's raw materials and products; manages a worldwide cooperative research program; provides a voice for our industry on Capitol Hill; and is the go-to resource for technical reports and publications.

[6] 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.

[7] AFPM is the leading trade association representing the makers of the fuels that keep Americans moving and the petrochemicals that are the essential building blocks for modern life. Our industries make life better, safer, healthier and — most of all — possible.

[8] API and GPA are submitting a separate comment letter that expresses their views on issues related to gas gathering pipelines.

[9] Pipeline Safety: Gas Pipeline Leak Detection and Repair, 88 Fed. Reg. 31890 (May 18, 2023).

[10] For the LDAR rulemaking, these materials are available in public docket PHMSA-2021-0039.

[11] Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 88 Fed. Reg. 64518 (September 19, 2023). In fact, PHMSA initially allocated only three days for the GPAC to consider its Leak Detection proposal. However, it quickly became apparent that additional time would be required for the Committee to complete its review of its Leak Detection proposed rule, and PHMSA modified the agenda for this meeting by deferring consideration of its Class Location proposed rulemaking to a future GPAC meeting.

required to hear all perspectives from a wide range of interested stakeholders, the five days allocated to review this proposed rule were insufficient for the Committee to adequately review and provide feedback on all the topics related to the NPRM included on the Committee's agenda. PHMSA subsequently scheduled a second GPAC meeting, which was held in Arlington, Virginia from March 25 to March 29, 2024.[12] Due to the overlapping and interrelated nature of the topics discussed during the November 2023 and March 2024 meetings, the Associations are submitting comments responding to the discussions, findings, and recommendations of the Committee from both the November and March meetings in this document.[13] [14]

The GPAC, PHMSA's peer-review, technical advisory committee focused on natural gas pipeline safety and environmental regulatory initiatives, is, by statute, responsible for reviewing and providing input and recommendations to PHMSA on proposed regulatory actions to assure the technical feasibility, reasonableness, cost-effectiveness, and practicability of those actions.[15] The input and recommendations provided to the Agency by the Committee are critical to efforts to reach consensus around highly technical and complex regulatory proposals. The Associations believe that the input, insight, and recommendations of the GPAC are particularly important in the case of a regulatory proposal like the proposed LDAR rule, which introduces significant novel and technically complex requirements focused not only on pipeline safety, but also on reducing methane emissions.

Throughout both the November and March meetings, the GPAC generally voted on concepts and principles, rather than specific regulatory language. Given the technical and complex nature of the subject matter, and the sheer breadth of topics discussed, the Associations are providing recommended modifications to the regulatory text included in the proposed rule for PHMSA's consideration. The Associations believe the modifications shown in **red** reflect the changes to the proposals from the NPRM that were endorsed by the GPAC during the meeting. The Associations have also identified areas of additional concerns, shown in **blue**, that were not directly voted on by the GPAC but were shared during public comment or identified through written comments by the Associations. Text without markup is identical to the language proposed in PHMSA's LDAR NPRM.

These comments are intended to supplement the comments previously submitted to PHMSA by the Associations regarding this rulemaking and do not replace the comments the Associations submitted to the Agency on August 16, 2023. As discussed at length in our August 2023 comments, pipeline safety remains the top priority of the Associations and our members. Additionally, the Associations and our members remain committed to reducing methane emissions through the implementation of reasonable leak detection and repair requirements consistent with Congress' mandate in Section 113 of the PIPES Act, smart innovation, new and

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[12] Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 89 Fed. Reg. 12798 (February 20, 2024).

[13] For example, the Committee considered the effective dates of various provisions of a potential LDAR final rule, as well as enhanced regulatory reporting requirements during the March 2024 meeting. Both of these concepts were introduced, briefly discussed, but ultimately tabled during the November meeting. Requiring public commenters to provide meaningful reactions, responses, and recommendations to partial and incomplete discussions is not helpful to the rulemaking process and will likely only cause confusion in the record and for PHMSA staff.

[14] The Associations note that they received several assurances from PHMSA staff confirming that the Agency would accept comments responding to both the November 2023 and March 2024 GPAC meetings after the conclusion of the March 2024 meeting. Additionally, the Associations note that because the GPAC did not formally vote to adopt the transcript of the November 2023 and March 2024 meetings, together with presentation slides documenting the Committee's votes during each meeting, as the report the GPAC proceedings regarding the LDAR rulemaking until the last day of the March 2024, comments filed in response to both the November and March GPAC meetings are timely. *See* GPAC Transcript, March 27, 2024, at pages 152 – 154.

[15] 49 U.S.C. §60115

modernized infrastructure, the adoption of best practices for the detection and repair of leaks, and the deployment of advanced technologies that maintain reliable, resilient, and cost-effective energy service choices for consumers.[16]

The Associations continue to encourage PHMSA to strike an appropriate balance between prescriptive regulations and a performance-based approach that provides operators the flexibility to take necessary actions to ensure safety and reduce methane emissions while delivering gas reliably and affordably to the 78 million homes and business who depend on natural gas as an essential energy source. Accordingly, the Associations urge PHMSA to carefully consider the recommendations of the Committee, as well as these comments, as the Agency works towards developing a final LDAR rule that advances pipeline safety, helps reduce methane emissions, and that is reasonable, technically feasible, practicable, and cost-effective.

A. The Associations Have Continued Concerns Regarding PHMSA's Risk Assessment

As discussed at length in our comments submitted on August 16, 2023, and during both sessions of the GPAC meeting, the Associations have significant concerns regarding the PRIA developed by PHMSA for this rulemaking and continue to strongly encourage the Agency to revise, update, and correct the risk assessment for this rulemaking so that it accurately reflects the costs and benefits of this significant regulatory action. The Pipeline Safety Act requires PHMSA to conduct a risk assessment for each pipeline safety standard proposed under 49 U.S.C. § 60102. Section 60102(b)(3) states that in preparing a risk assessment PHMSA must:

> (A). Identify the regulatory and nonregulatory options that the [Agency] considered in prescribing a proposed standard;
> (B). Identify the costs and benefits associated with the proposed standard;
> (C). Include—
>> (i) an explanation of the reasons for the selection of the proposed standard in lieu of the other options identified; and
>> (ii) with respect to each of those other options, a brief explanation of the reasons that the [Agency] did not select the option; and
>
> (D). Identify technical data or other information upon which the risk assessment information and proposed standard is based.

As part of the rulemaking process, the Pipeline Safety Act requires PHMSA to make the risk assessment for a proposed standard "available to the general public" for comment and to present the risk assessment information to the Gas Pipeline Advisory Committee (GPAC) for peer review. Failing to comply with the risk assessment requirements in the Pipeline Safety Act in developing a proposed standard violates the Pipeline Safety Act and provides a basis for vacating any subsequent final rule. Failing to provide an accurate and complete risk assessment that reflects the actual costs and benefits of a proposed rule prevents the GPAC, regulated entities, the public, and other stakeholders to properly assess a proposed rule's impact.

We continue to urge the Agency to refine and, where necessary, revise its risk assessment so that all interested stakeholders can offer informed recommendations and suggestions during this rulemaking process. PHMSA should notify the GPAC of its intent to develop a revised risk assessment in providing the 90-day written response that is required under the Pipeline Safety

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[16] *See* Section III of the Associations' August 2023 comments for a detailed description of the industry's commitments to reducing methane emissions.

Act. Section 60102(b)(4)(C) specifically states that "[n]ot later than 90 days after receiving a report submitted by the [GPAC]," the Agency is required "to review the report" and "provide a written response to the committee that is the author of the report concerning all significant peer review comments and recommended alternatives contained in the report." PHMSA has advised the GPAC that the transcript of its public meetings, along with the slide decks and related materials, constitute the report that is required by the statute. The GPAC also voted to approve the materials from its November 27, 2023, to December 1, 2023, and March 25 to 27, 2024, public meetings as its report in this proceeding.

The GPAC spent more than seven days reviewing numerous aspects of the Proposed Rule and its report contains a variety of significant peer review comments and recommended alternatives, including with respect to the preliminary risk assessment. Many of the GPAC's recommendations depart significantly from the Agency's original proposals, and PHMSA must provide a written response to these peer review comments by no later than June 25, 2024, to meet the 90-day statutory deadline. Failing to do so would be a clear violation of the Pipeline Safety Act and have the effect of depriving the GPAC and other interested stakeholders of information that Congress directed be disclosed in a timely fashion as part of the rulemaking process.

Of particular concern to the Associations, PHMSA's failure to provide a written response by the 90-day deadline will prejudice stakeholders who wish to engage with OMB's Office of Information and Regulatory Affairs (OIRA) during the regulatory review process that is required under Executive Order 12866, Regulatory Planning and Review. OIRA serves an important function in the rulemaking process, particularly with respect to reviewing the regulatory and cost-benefit analyses that Federal agencies prepare in issuing new regulations, and interested stakeholders are allowed to submit written comments and request a meeting with OIRA before the issuance of a final rule.

Having access to PHMSA's 90-day written response to the GPAC report will allow stakeholders to engage more effectively with OIRA in submitting comments and participating in public meetings. That is particularly true in this proceeding, where, as noted in our August 2023 comments, the Agency failed to comply with the statutory requirements and fundamental principles of OMB's guidance in developing the preliminary risk assessment for the Proposed Rule. Stakeholders have a right to understand how PHMSA intends to address these concerns before engaging with OIRA, the entity within the Executive Branch that is tasked with reviewing the risk assessment and other documents that the Agency develops during the rulemaking process.

B. PHMSA's Reliance on the 2020 Weller Study is Misplaced.

PHMSA's continued reliance on the 2020 Weller study to quantify and evaluate methane emissions from gas distribution mains is misplaced. As discussed at length in the Associations' August 2023 comments, the Weller study does not provide a reasonable basis for evaluating methane emissions from gas distribution mains. Due to several shortcomings, the Weller Study yields results that are significantly inconsistent with all other previous studies and should not be used to support rulemaking decisions.[17] In particular, the Weller study's estimated emissions from distribution mains are wildly skewed by errors made in its evaluation of protected and unprotected steel mains as well as limitations on the use of top-down measurements that are not paired in

[17] *See* section V.C of the Associations' Aug. 16, 2023, comments for an extensive and detailed discussion of the Associations' concerns regarding PHMSA's reliance on the Weller study as a basis for this pending rulemaking.

time and place with bottom-up facility and equipment measurements together with operational information. Most significant, the authors of the Weller study appear to misidentify and misunderstand the categories of protected and unprotected steel pipe as defined under 49 C.F.R. §§ 192.455, 192.457, and 192.479 and how gas distribution companies annually report their mileage of distribution pipe by material and level of protection to PHMSA under 49 C.F.R. § 191.11 on DOT Form PHMSA F 7100.1-1 (Annual Distribution Report). The Weller study did not make this important distinction between cathodic protection and the lack of cathodic protection. As a result, the authors included leak measurements on unprotected coated steel in their category of protected steel. As a result, they calculated a very inflated emissions leak rate for what they (wrongly) assumed came from "protected" steel. This led them to conclude – illogically – that protected steel leaks more than unprotected steel. In fact, the opposite is true. The U.S. Environmental Protection Agency, in its August 1, 2023 proposed rule, "*Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determination for Petroleum and Natural Gas Systems*", expressly acknowledged these significant shortcomings with the Weller study and opted to no longer to rely on the study when developing revisions to the pipeline main equipment leak emission factors used in Subpart W.[18] The Associations urge PHMSA to follow EPA's lead and no longer rely on the flawed Weller study in rulemaking. Rather, PHMSA should base this rulemaking on the best available evidence, including the 2015 Lamb et al. study.

C. Future Agency Stakeholder Engagement and Outreach

Due to the significant impact this rule will have on operator's Operations & Maintenance (O&M) plans, the Associations believe it will be necessary for PHMSA to provide additional guidance through FAQs and public workshops. Any future guidance proposed by the Agency regarding the implementation of any final LDAR rulemaking should be published for public comment prior to finalization. Additionally, the Associations specifically request the opportunity for public comment opportunities related to harmonizing any final LDAR rule with several final EPA regulations, including the recently finalized rule, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review"[19] and the anticipated forthcoming revisions to Subpart W of the Greenhouse Gas Reporting Program, to minimize duplicative or inconsistent regulatory requirements and help facilitate compliance with both agencies' regulations.

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[18] In its proposed rule revising Subpart W of the GHGRP, EPA reached the following conclusion:

> *In the 2022 Proposed Rule, we proposed to revise the pipeline main equipment leak emission factors using a combination of data from Lamb et al. (2015) and Weller et al. (2020). We sought comment on the approach of combining data from these two studies. We received numerous comments regarding the classification of pipeline materials and respective quantified leaks in the Weller et al. (2020) study. In response to these comments and as discussed in more detail below,* ***we agree with commenters that the categorization of pipeline leaks by material type likely resulted in inaccuracies specifically for the unprotected and protected steel pipeline material types****. In this rulemaking, we are continuing to propose revisions of the equipment leak pipeline main emission factors using more recent study data, but instead of combining data from Lamb et al. (2015) and Weller et al. (2020), we are proposing to rely only on the Lamb et al. (2015) study*

(emphasis added).

[19] *See* Standards of Performance for New, Reconstructed, and Modified Sources and emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 89 C.F.R. 16,820 (March 8, 2024).

II. Transmission Pipeline Blowdown Mitigation

A. Discussion

1) PHMSA must clarify that operators are required to *reduce*, not *minimize*, emissions using the methods specified in § 192.770.

As stated in the Associations' comments on the LDAR NPRM, the Associations support PHMSA's intention to provide flexibility for operators to select the emission mitigation solution right for each specific operating environment, with consideration for safety, cost of implementation, and reliability of service. The Associations believe this flexibility is critical and support PHMSA's approach of providing a menu of options for mitigating vented emissions, as specified in § 192.770(a)(1)-(6).[20]

To ensure universal understanding of the regulation, however, additional clarity on the term "minimize" is necessary from PHMSA. Without direction on how PHMSA interprets the term "minimize," the mandate may be understood to mean that an operator is to select a single method (or combination of methods) in § 192.770(a) that achieves the greatest theoretical emissions mitigation, to the exclusion of all other methods (or combination of methods). It is unreasonable to require operators to evaluate and document the practicability of every permutation of emissions mitigation methods as required in § 192.770(c) for each and every planned venting scenario, even if the methods evaluated by the operator are standardized in procedures, as delineated in § 192.770(a). This is especially true given that "minimizing" emissions may inadvertently *require* flaring whenever it is an available method (as per § 192.770(a)(5)). Moreover, § 192.770(a)(6) allows an indeterminate number of "alternative methods" that would also require evaluation for emissions minimization (either as a standalone method or in combination with other methods) for every venting scenario.

PHMSA has stated in the preamble[21] that it intended to allow operators to choose from a menu of proven emission mitigation options. The Agency also proposed in § 192.770(c) that the operator must document the selected methodology and describe how the methodologies minimize the release of gas to the environment. Operators should not be required to document "how" methodologies minimize the release of gas to the environment. This additional documentation is not necessary since each process noted in § 192.770(a) is a mechanism to minimize the volume of natural gas in the pipeline that is vented, or to combust the methane to reduce emissions. PHMSA must provide the clarity necessary to reflect this intent. Failure to provide this flexibility would

[20] NPRM at 31948
[21] NPRM at 31948.

necessarily cause an increase in true costs to operators through the application of multiple mitigation methods and would require detailed and individualized justifications for each pipeline blowdown strategy, while significantly decreasing net benefits in the PRIA.

2) PHMSA should limit the applicability of § 192.770 (and § 193.2523) to planned releases that would exceed a volume *well in excess* of "de minimis" releases.

During the GPAC Meeting, the Committee agreed on a set of principles related to the applicability of the emissions mitigation requirements proposed in §§ 192.770 and 193.2523. The Committee agreed upon the following list of example "de minimis" releases that should not be subject to the emissions mitigation requirements[22] in §§ 192.770 and 193.2523:

- blowdowns of launchers and receivers;
- blowdowns from work on measurement and regulation stations;
- blowdowns from maintenance work on compressor units and associated equipment including relief systems and filter separators;
- blowdowns to conduct an immediate anomaly repair and excavation; and
- ESD testing, as relevant

GPAC also agreed that the volumetric "floor" for applicability should be set at a level that was sufficiently in excess of the "de minimis" vented emissions examples, so that those scenarios would *never* be subject to the requirements in §§ 192.770 and 193.2523[23]. Setting the floor at or near a "de minimis" volume would be inappropriate, as it would contradict the plain intention of Section 114 of the PIPES Act of 2020, as well as the principles agreed to by the GPAC. The "floor" most commonly proposed by GPAC members was 500 MCF

[22] *See* GPAC Voting Slide # 4 Blowdown Mitigation (§ 192.770). Bullet #2

[23] *See* GPAC Transcript November 27, 2023.

Pages 216-217. Dr. Ravikumar "I agree with this approach on the principles of what emissions to include and exclude for this specific criteria. . . . I was looking at all the data that are available on blowdown related emissions, and it covers I think one, two, and three for the most part for which we already, we have available data on. So what I'm thinking is we know this. If we agree on this, then we'll look at what are all the emissions that we know of from blowdowns associated with these events, and set a threshold that's way beyond that so that we know for sure the threshold excludes all of these emissions. And just by looking at the data, that threshold is anywhere between .2 and .5 mmcf. And if we take as a threshold, by definition that threshold will exclude emissions from all of these categories."

Pages 220-221. Ms. Gosman "I like these principles. And I also feel the need to clarify again because I don't think I was clear before that actually the number I was suggesting was .5, right, mmcf, just to make sure that everybody understood. So you know, I think Arvind's data is really important to this discussion. I think it's on the record. I like having that on the record. I think this helps us to understand again sort of what we're trying to get at here, and for that reason I like it. I don't think we need a number on the record, but if we were to have that, right, I think I'd want to do the range that Arvind mentioned."

(thousand cubic feet) and aligns with the Committee's recommended volumetric criterion for large-volume gas release reporting.

In order to provide the clarity necessary to operators and regulators, PHMSA should follow GPAC's recommendation and prescribe a minimum volume, below which emissions mitigation will never be required by the regulation.[24]. Prescribing a minimum volume of 500 MCF (thousand cubic feet) is appropriate.

B. Updated regulatory text redline

§ 192.770 Reducing~~Minimizing~~ emissions from gas transmission pipeline blowdowns.

(a) Except as provided in paragraph (b) of this section, when an operator performs any intentional release of gas **that exceeds 500 MCF without mitigative action** (including blowdowns or venting for scheduled repairs, construction, operations, or maintenance) from a gas transmission pipeline, the operator must prevent or ~~**minimize**~~ **reduce** the release of gas to the environment through one or more of the following methods:

- (1) Isolating the smallest section of the pipeline necessary to complete the task by use of valves or the installation of control fittings;
- (2) Reducing pressure by use of in-line compression;
- (3) Reducing pressure by use of mobile compression to a segment or storage vessel adjacent to the nearest isolation valves;
- (4) Transferring the gas to a segment of a lower pressure pipeline system adjacent to the nearest isolation valves;
- (5) **If methods (1) through (4) are determined to be impractical, unsafe, or result in lower emissions abatement,[25] then r**outing gas released from the pipeline from the nearest isolation valves or control fittings to a flare or to other equipment as fuel gas[26]; or
- (6) Employing an alternative method demonstrated to result in a release volume reduction of at least 50% compared to venting gas directly to the atmosphere without mitigative action.

(b) An operator is not required to comply with the provisions of paragraph (a) **if, in the judgment of the operator, one of the following occurs:**

- **(1)** during an event that activates its emergency plan under § 192.615(a)(3), **or an event that requires immediate investigation of the serviceability of the pipeline facility,** when such ~~**minimization**~~ **reduction** would delay the response or result in a safety risk during pipeline assessments or maintenance. Each ~~**emergency**~~ release conducted without mitigation **due to activation of an emergency plan**

[24] Operators may choose to voluntarily apply emission mitigation strategies below the threshold. These voluntary actions, not explicitly required by regulation, are consistent with the PIPES Act of 2020 Section 114 mandate.

[25] *See* GPAC Voting Slide # 6 – Blowdown mitigation (§ 192.770).

> "Sole use of flaring is limited to when the other options are impractical, unsafe, or result in lower emissions abatement. GPAC supports continued research and development to advance technology, and does not intend for this recommendation to limit technological advancement in this area."

[26] Note that the Associations' recommended edit has moved the method described in § 192.770(a)(2) of the NPRM to § 192.770(a)(5).

or immediate investigation must be documented, including the justification for release without mitigation;

(2) application of a method in paragraph (a) will result in a significant negative impact to customers, such as customer outages or rate shock[27];[28]

(3) any intentional release of gas that would not exceed 500 MCF (thousand cubic feet)[29&30]

(c) Operators must document **in their procedures** the methodologies used in paragraph (a) **of this section** and describe how the methodologies **comply with that paragraph.[31]** ~~**minimize the release of gas to the environment.**~~

[27] *See* GPAC Voting Slide # 5 – Blowdown mitigation (§ 192.770).

> "In addition to the proposed exception for when there is a negative impact on safety, add an exception for when there would be a significant negative impact to customers, such as outages or significant rate shock. Operators must document the justification and rationale for such exceptions subject to the reporting requirements in agenda item 6. The GPAC recommends PHMSA address, as appropriate, scenarios that would affect customer outages."

[28] Note: The GPAC's recommendation included reference to a future recommendation concerning reporting. For the purposes of these comments, the Associations did not address reporting as it will be discussed in a subsequent GPAC meeting.

[29] *See* GPAC Voting Slide # 4 Blowdown Mitigation (§ 192.770). Bullets #1 and 2

- PHMSA should create an exception to § 192.770 for non-emergency blowdowns with a de minimis volume consistent with the principles outlined below and considering available data on releases from blowdowns.
- The GPAC recommends this section address blowdowns of large-diameter pipeline segments but exclude de minimis emissions, including:
  - blowdowns of launchers and receivers that may not be within the confines of a compressor station;
  - blowdowns from work on measurement and regulation stations;
  - blowdowns from maintenance work on compressor units and associated equipment including relief systems and filter separators;
- Blowdowns to conduct an immediate anomaly repair and excavation; and
- ESD testing as relevant.

[30] To accomplish a test of the full functionality of an ESD system, that system should be periodically vented to atmosphere. This test of the full system will, among other things, determine if the venting time meets the design criteria and confirm that valves will fully operate over the pressure ranges and differentials that are encountered during an ESD.

[31] *See* GPAC Voting Slide # 7 – Blowdown mitigation (§ 192.770).

> "Revise 192.770(c) to read as follows - Operators must document in their procedures the methodologies used in paragraph (a) of this section and describe how the methodologies comply with that paragraph."

III. Pressure Relief Devices

A. Discussion

For simplicity, the Associations recommend merging of proposed § 192.773 into existing of § 192.739. Operators currently take significant steps in the design, construction, operations, and maintenance of relief valves to ensure that pipelines are protected from overpressurization. The proposed regulations seek to apply an engineering review of relief valves to minimize methane emissions during an event. The purpose of a relief valve is to vent sufficient gas during an overpressure event to ensure the downstream pipelines protected by the relief valve remain safe. The relief valve automatically reseats when the pressure is reduced below the set point. Pipelines and overpressure protection strategies are guided by company standards, based on longstanding engineering standards, practice, and analysis. Therefore, individual engineering analyses demonstrating minimization of gas releases for each and every relief valve is neither necessary nor appropriate.

The associations recommend the deletion of § 192.199(i)(1). Relief valves automatically reseat when the pipeline pressure recedes below the set pressure. The set pressure is established to protect the pipeline as required by § 192.201. The location of the relief valve sensing line is installed per the manufacturer's recommendations and engineering standards to ensure the valve operates as intended.

The Associations recommend revisions to § 192.199(i)(2) to utilize accurate terminology commonly used by industry. The industry recommends the use of "designed pressure range" instead of "set and reset actuation". Operators cannot control actuation reset pressure and therefore PHMSA's proposed language is misleading and likely to result in implementation challenges.

Lastly, the Associations recommend modified language for § 192.739(c)(1) to remove the reference to pressure gauges. Pressure gauges are calibrated outside the relief valve inspection process and therefore a reference to them in this section is incorrect.

B. Updated regulatory text redline

§ 192.199 Requirements for design and configuration of pressure relief and limiting devices.

* * * * *

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard to public safety;

* * * * *

(i) All new, replaced, relocated, or otherwise changed pressure relief and limiting devices must be designed and configured, as demonstrated **by** documentation, such as engineering standards~~ed engineering analysis~~[32], to minimize ~~unnecessary~~ releases of gas by ensuring each of the following:

(1) ~~The set and reset actuation pressure of the pressure relief device and where pressures are taken must minimize release volumes beyond what is necessary to provide adequate overpressure protection~~;

(2) The design (including sizing and material) and configuration of the pressure relief device and its associated piping must be appropriate for its **designed pressure range**, ~~**to minimize pressure choking**~~,[33] compatible with the composition of transported gas, and suitable for reliable operation in expected operating and environmental conditions; and

(3) Installation of **a replaced or relocated** ~~**the**~~ pressure relief device must include ~~**upstream and downstream**~~[34] isolation valve**(s)** to facilitate testing and maintenance.

~~**§ 192.773 Pressure relief device maintenance and adjustment of configuration.**~~

§ 192.739 Pressure limiting and regulating stations: Inspection, ~~and~~ testing, maintenance, and records.[35]

(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of § 192.201(a); and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

(b) For steel pipelines whose MAOP is determined under § 192.619(c), if the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows:

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[32] *See* GPAC Voting Slide # 8 – Operations and Maintenance and Venting. Pressure relief devices (§§ 192.199 & 192.773). Item #1.

"PHMSA should remove the term "documented engineering analysis." and instead simply refer to documentation, including engineering standards."

[33] Associations Comment: This is a term not commonly used in industry. The concept of pressure choking is adequately addressed by relief valve manufacturers during the design of the relief valve and should not be included in a list of considerations for individual operators installing the valves.

[34] *See* GPAC Voting Slide # 8 – Operations and Maintenance and Venting. Pressure relief devices (§§ 192.199 & 192.773). Item #4.

"Remove the requirement for upstream and downstream isolation valves and instead require the ability to isolate the relief valve for maintenance and testing."

[35] *See* GPAC Transcript November 27, 2023.

Page 378. Mr. Squibb "PHMSA should incorporate the changes to device maintenance into existing 192.739."

Associations Comment: The GPAC discussed the correct place in the federal regulations for this requirement, but the recommendation was not incorporated into the GPAC voting slide

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 percent of SMYS	MAOP plus 4 percent.
Unknown as a percentage of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

(c) Each operator must develop, maintain, and follow written operations and maintenance procedures to assess the proper function of pressure limiting or relief device**s** and to repair or replace each failed pressure limiting or relief device. When a pressure limiting or relief device fails to operate or allows gas to release to the atmosphere at an operating pressure above or below the set actuation pressure range defined for the device in the operator's operations and maintenance procedure, the operator must:

(1) Assess the pilot, springs, seats, ~~**pressure gauges,**~~ and other components to ensure proper functioning, sensing, and set/reset actuation pressures are within actuation pressure tolerances;

(2) Assess the inlet and outlet piping for piping that restricts the inlet or outlet gas flow, piping that restricts the sensing pressure, debris, and other restrictions that could impede the operation or restrict the capacity to relieve overpressure conditions;

(3) Repair or replace the device to eliminate the malfunction as follows:

(i) If a pressure relief device activates above its set pressure and above the pressure limits in § 192.201(a) or § 192.739**(b)** as applicable, fails to operate, or otherwise fails to provide overpressure protection, the operator must **take immediate action to ensure overpressure protection. For malfunctioning equipment, the** repair or replace**ment of** the device or pressure sensing equipment ~~**immediately**~~ **must occur as soon as practicable**.[36]

(ii) If a pressure relief device allows gas to release to the atmosphere at an operating pressure below the set actuation pressure range, the

[36] *See* GPAC Transcript November 27, 2023.

Page 394. Mr. Zamarin. "You have to immediate stop any emissions that are being caused as a result of the malfunction of the device. And then it's setting a 30-day requirement to repair or replace the device. So, this is not like we're, we're not talking about allowing the device to be venting for 30 days or longer. I do think we, we have to have – we have in this section an immediate action to stop the release until the device is repaired, but then it says its then limiting the timeline for repair to 30 days. I think that having a practicable standard is important. I mean, supply chain issues, permitting issues, relief valves, once the issue has been addressed I think operators need the ability to schedule those repairs and, manage those appropriately.

Page 396. Mr. Zamarin "I think you'd have to make sure the language is in a way that it's clear, that the 30 days is not a limit. Because when I hear that, it sounds like a limit. You know, you have – I would – its always the thing ---"

Mr. Danner "But, again, or as soon as practicable. So, if its not practicable, the 30 days gets extended until you can get it done."

Mr. Zamarin "Yeah. I, I'd be fine with that conceptually, except for the fact that I'm not sure where I get the 30 days as a target or a goal, but…"

Page 398. Mr. Chace "I'll say first of all I think industry's concerns about the 30 hard cap are legitimate."

operator must take immediate ~~**and continuous**~~[37] action ~~**with on-site personnel**~~[38] to stop the release until the device is repaired or replaced. ~~**The relief device or pressure sensing equipment must be repaired or replaced as soon as practicable but within 30 days.**~~ **An operator must promptly repair or replace the relief device or pressure sensing equipment, but no later than 30 days after the malfunction has been identified, unless the operator demonstrates that 30 days is impracticable**. [39]

(d) Each operator must develop, maintain, **document** and follow written operations and maintenance procedures to ensure that a pressure relief device configuration~~**, as demonstrated by a documented engineering analysis,**~~[40] employs set and reset actuation pressures ensuring ~~**minimization**~~ **mitigation** of release volumes while providing adequate overpressure protection.

(e) Records under this section must be maintained as follows:

(1) Records of relief device~~s~~ malfunctions**, as well as the method of repair, replacement, or reconfiguration,** must be maintained for 5 years ~~**after repair or replacement.**~~

~~**(2) Records pertaining to repair, replacement, or reconfiguration (including any engineering analyses) of a pressure relief device must be maintained for the life of the pipeline.**~~[41]

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[37] *See* GPAC Transcript November 27, 2023.

Page 66. Mr. Nanney "And a note from PHMSA is that we will clarify that continuous action is no longer necessary following the cessation of a release and the implementation of alternative overpressure protection measures."

Page 378. Mr. Squibb "Operators must take immediate action, not continuous action, to address malfunctions."

Page 415. Mr. Weisker "… we take immediate action and go out and respond to it. And then that, that corrective action could be complete and we would be in a stable condition that you don't need to have someone there, continuously there, until you get to a point later."

Page 416. Mr. Zamarin "But if you've gotten to the location, you've address it from an immediate perspective, and it's safe until the repair can be made, this section would require someone to be there continuously until the repair is made. And I don't – I think – I don't think that make sense from our perspective."

[38] *See* GPAC Voting Slide # 8 – Operations and Maintenance and Venting. Pressure relief devices (§§ 192.199 & 192.773). Item #2.

"PHMSA should remove the term "PHMSA remove the term "with onsite personnel" from § 192.773(a)(3)(ii)."

[39] *See* GPAC Voting Slide # 8 – Operations and Maintenance and Venting. Pressure relief devices (§§ 192.199 & 192.773). Item #3.

"PHMSA clarify the repair timelines to be 30 days, unless the repair timeline is impracticable, in which case the repair must be completed as soon as practicable."

[40] *See* GPAC Voting Slide # 8 – Operations and Maintenance and Venting. Pressure relief devices (§§ 192.199 & 192.773). Item #1.

"PHMSA should remove the term "documented engineering analysis." and instead simply refer to documentation, including engineering standards."

[41] The Associations encourage PHMSA to revise the recordkeeping provisions to provide clarity on the necessary records for compliance with this regulation. The Associations strongly discourage PHMSA from periodically adding regulations that require operators to maintain some (but not all) records for the life of the pipeline. This creates regulatory confusion and potentially contradicts other sections of the regulation. In this situation, a record of a past relief valve malfunction - that has been properly repaired and subsequently retested 5-years later - is irrelevant to the current operations. PHMSA also incorrectly states in the PRIA that "since the proposed rule does not require the records to be kept in a specific format, PHMSA expects no changes to the baseline recordkeeping procedures currently used by operators, and therefore no incremental costs." This assumption is incorrect. Maintaining records for 5-years versus. for the life of an asset require different protocols, storage solutions, and oversight. Without justifying why those records are needed for such a prolonged period, PHMSA must modify their proposed regulation.

IV. Leak Survey – Transmission

A. Discussion

The GPAC endorsed the changes proposed in the LDAR NPRM to § 192.706.

The Associations offer one suggested edit under § 192.706(d). The proposed regulatory text included a list of common natural gas distribution pipeline materials with a propensity of leakage. This list is out of place in a transmission section of regulations. Therefore, the Associations recommend the list of examples be removed.

B. Updated regulatory text redline

§ 192.706 Transmission lines: Leakage surveys.

(a) General. Each operator must perform periodic leakage surveys in accordance with this section. Each leakage survey must be conducted according to the advanced leak detection program requirements in § 192.763, except that human or animal senses may be used in lieu of leak detection equipment only in the following circumstances:
- (1) An offshore gas transmission pipeline below the waterline or offshore gathering pipeline below the waterline, or
- (2) An onshore transmission line outside of an HCA or a gathering pipeline, each either in a Class 1 or Class 2 location, with advance notification to PHMSA in accordance with § 192.18. The notification must include tests or analyses demonstrating that the survey method would meet the ALDP performance standard in § 192.763(b) or (c) (as applicable).

(b) Frequency of surveys. Except as provided in paragraphs (c) and (d) of this section, leakage surveys must be performed at the following intervals:
- (1) Pipelines outside of HCAs must be surveyed at least once per calendar year, but with an interval between surveys not to exceed 15 months; and
- (2) Pipelines in HCAs must be surveyed as follows:
  - (i) In Class 1, Class 2, and Class 3 locations, at least twice each calendar year, with intervals not exceeding 7 ½ months;
  - (ii) In Class 4 locations, at least four times each calendar year, with intervals not exceeding 4 ½ months.

(c) Non-odorized pipelines. Leakage surveys for pipelines transporting gas in conformity with § 192.625 without an odor or odorant, must perform leakage surveys using leak detection equipment at the following intervals:
- (1) In Class 3 locations, at least twice each calendar year, at intervals not exceeding 7 ½ months.
- (2) In Class 4 locations, at least four times each calendar year, at intervals not exceeding 4 ½ months.

(d) Valves, flanges and certain other facilities. Leakage surveys of all valves, flanges, pipeline tie-ins with valves and flanges, ILI launcher and ILI receiver facilities, and pipelines known to leak based on material ~~**(including, cast iron, unprotected steel, wrought iron, and historic plastics with known issues)**~~, design, or past operating and maintenance history, must be performed at the following intervals:

(1) In Class 1, Class 2, and Class 3 locations, at least twice each calendar year, at intervals not exceeding 7 ½ months.
(2) In Class 4 locations, at least four times each calendar year, at intervals not exceeding 4 ½ months.

V. Transmission Pipeline Patrols

A. Discussion

The Associations support the GPAC-recommended changes to the frequency of gas transmission pipeline patrols.

B. Updated regulatory text redline

§ 192.705 Transmission lines: Patrolling.[42]

(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

(b) ~~Operators must conduct~~ P atrols ~~at least~~ must be performed at the following intervals:

(1) Pipelines in Class 3 and 4 locations, at least 6 ~~12~~ times each calendar year at intervals not exceeding 75~~45~~ days;

(2) Pipelines in Class 1 and 2 locations, at least 4 times each calendar year, at intervals not exceeding 135 days.[43]

(c) Methods of patrolling include walking, driving, flying, satellite or other appropriate means of traversing or viewing the right-of-way.

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[42] *See* GPAC Voting Slide # 10 – Gas transmission patrols (§ 192.705). Bullet #2.
"Discussion of reporting in agenda item 6."
Note: The GPAC's recommendation included reference to a future discussion concerning reporting. For the purposes of these comments, the Associations did not address reporting as it will be discussed in a subsequent GPAC meeting.

[43] *See* GPAC Voting Slide # 10 – Gas transmission patrols (§ 192.705). Bullet #1
"The patrol frequency is revised to 6 times each calendar year at intervals not exceeding 75 days for Class 3 and 4 locations, and a patrol frequency revised to 4 times each calendar year in Class 1 and 2 locations."

VI. Leak Survey – Distribution

A. Discussion

1) For inside jurisdictional service line piping, preserving a 5-year leakage survey frequency is appropriate and necessary.

In establishing the leak survey frequencies in § 192.723, it is critical that PHMSA distinguish between interior service lines and buried (exterior) service lines. GPAC acknowledged that distinct leak survey frequencies may be appropriate for these facilities, given the existing literature, the known differences in leak proneness between these two different environments, and the precedent of the regulatory amendments to § 192.481 that extended the frequency of atmospheric corrosion inspection requirements of onshore service lines to five years.

In its 2021 final rule[44] easing the regulatory burdens on the construction, maintenance, and operation of gas transmission, distribution, and gathering pipeline systems , PHMSA stated:

> *"Alignment of atmospheric corrosion inspection intervals with those for leakage surveys in § 192.723 will allow greater scheduling flexibility for operators and decreased costs arising from less frequent atmospheric inspections. As stated in the NPRM, PHSMA is unaware of any pipeline incidents arising from atmospheric corrosion on a service line. In addition, PHMSA has approved State waivers in the past that have allowed certain operators to perform both atmospheric corrosion and leakage surveys on a 4-year interval outside of business districts and subject to certain conditions. The most recent of these was for North Western Energy in South Dakota, issued March 2, 2019. PHMSA has not observed an increase in leaks or incidents from this and other State waivers. For these reasons, PHMSA finds that a longer atmospheric corrosion inspection interval is supported in areas with low observed atmospheric corrosion risk. The final rule applies the new 5-year inspection interval to distribution service lines. Although PHMSA acknowledges that operators have reported atmospheric corrosion incidents on distribution mains, PHMSA understands the design and operational characteristics of service lines make them less susceptible to atmospheric corrosion induced failure"*[45]

The potential for a service line to develop a leak due to corrosion is based on both the material of the line and its exposure to a corrosive environment. For example, external corrosion is a concern on buried, unprotected bare steel,

[44] Pipeline Safety: Gas Pipeline Regulatory Reform, 86 Fed. Reg 2210. (Jan. 11, 2021).
[45] *Id.* at 2223.

whereas atmospheric corrosion is a threat to non-buried, interior service lines. Therefore, applying blanket leakage survey frequencies to both buried pipe and jurisdictional inside piping does not appropriately acknowledge their inherent differences in *what causes* them to leak and *how often* they leak.

Many urban-based gas distribution pipeline systems have extensive inventories of inside meter sets. Some of these urban operators have participated in a GTI study[46] that demonstrated extremely low leak rates on these inside service lines, based on as-found field data and extensive engineering analysis. The GTI study's conclusions included:

> *"A total of 15,505 random indoor corrosion and leak surveys were completed, 12,864 of which were located in New York State. This is a very large number of NY data points which allowed for the selection of high confidence levels of 90% to 95% when inferring the sample results to the broader NY or even operator-by-operator indoor asset population.*
>
> *. . .*
>
> *The proportion of the samples related to leak indications showed that 99% of the sites exhibited no leak indications while less than 1% had an indication of a leak with a median leak indication concentration level of 0.15% Gas."*

In addition to the negligible benefits, the cost of increasing leakage surveys of jurisdictional inside piping will also be disproportionately high. Furthermore, customers will largely bear the burden of compliance, as they would be required to provide the operator more frequent access to the inside service line in order for the leak survey to be performed. If a customer does not grant access, there is commonly a no-access fee or service disconnection imposed, and eventually the service may need to be interrupted and/or terminated so as to ensure that the operator remains in compliance with federal regulations. Customers may also bear the applicable rate increases associated with the additional leakage surveys.

In short, disallowing a five-year leakage survey interval for jurisdictional inside piping would significantly increase costs in return for negligible safety benefits. PHMSA should consequently allow a five-year survey frequency for this piping, regardless of whether it is located inside or outside a business district.

[46] Ersoy, Daniel & Farrag, Khalid. 2018. GTI Project 21858, *"Indoor Atmospheric Corrosion and Leak Survey Risk-Based Intervals".*

2) **PHMSA should establish a reasonable start of the proposed leakage survey for distribution pipeline systems with deficient readings identified during a cathodic protection test.**

It is critical that PHMSA establish a reasonable start for leakage surveys proposed in § 192.723 (d)(3) when cathodic testing shows deficient readings on anode-protected distribution pipeline systems. PHMSA's current proposal would require leakage survey on areas with deficient cathodic protection (CP) readings within the same calendar year that the CP readings were taken. If an operator takes these CP readings late in a calendar year, the proposed leakage survey schedule would leave an operator very little time to complete the leakage survey.

PHMSA should modify § 192.723(d)(3) to allow operators to conduct the leakage survey no later than 12 months from the date the deficient cathodic protection reading was found. PHMSA should also acknowledge that if the deficient CP reading is remediated to meet the applicable CP criterion before the 12-month leakage survey interval elapses, the leakage survey should not be required.

Relatedly, PHMSA should consider amending the proposed regulatory text in § 192.723(d)(3) to replace the phrase "cathodic protection survey" with "cathodic protection test," since the latter is the regulatory language used in § 192.465(a) to identify whether a deficient CP reading exists.

B. Updated regulatory text redline

§ 192.723 Distribution systems: Leakage surveys.

(a) *General.* Each operator of a gas distribution pipeline must conduct periodic leakage surveys with leak detection equipment in accordance with this section. All leakage surveys performed pursuant to this section must use leak detection equipment that meets the requirements of § 192.763.

(b) *Business districts.* Leakage surveys must be conducted at least once each calendar year, at intervals not exceeding 15 months, consisting of atmospheric tests at ~~each~~ gas, electric, telephone, sewer, water, or other system manhole**s**; crack**s** in the pavement and sidewalks; and any other location that provides an opportunity for finding gas leaks, **unless the following exception applies:**

(1) **the piping is inside a building and the operator is performing leakage surveys once every 5 calendar years not exceeding 63-months**

(c) *Non-business districts.* Leakage surveys must be conducted at least once every 3 calendar years, at intervals not exceeding 39 months, unless **one of the following exceptions apply:**

(1) a shorter inspection interval is required either by paragraph (d) of this section, the operator's operations and maintenance procedures, or the operator's integrity management plans under part 192, subpart P,

(2) the operator can demonstrate that a 5 calendar year leakage survey frequency, at intervals not exceeding 63-months, achieves an

equivalent or greater level of safety and environmental protection as a 39 month interval, or [47]

(3) the piping is inside a building and the operator is performing leakage surveys once every 5 calendar years not exceeding 63-months ~~and an extended interval is approved by the governing pipeline safety regulatory agency.~~[48]

(d) *Frequency of regular leakage surveys.* Leakage surveys must be conducted at least once every calendar year, at intervals not exceeding 15 months except as required in (d)(3) of this Section, for:

(1) Any known or previously identified cathodically unprotected distribution pipelines subject to § 192.465(e);

(2) Pipelines known to leak based on their material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), and the location of the pipe[49], design, or past operating and maintenance history; and

(3) Gas distribution pipeline systems protected by a distributed anode system, in the area of deficient readings identified during a cathodic protection ~~survey~~ test pursuant to § ~~192.463~~ 192.465 and Appendix D, until the cathodic protection deficiency is remediated. If the deficient cathodic protection reading cannot be corrected promptly, the initial leakage survey must be conducted no later than 12 months from the date the deficient cathodic protection reading was found.

~~(e) Investigating known leaks after environmental changes. An operator must investigate a known leak, including conducting a leakage survey for possible gas migration, as soon as practicable when freezing ground, heavy rain, flooding, or other changes to the environment occur that could affect the venting of gas or could cause migration of gas to the outside wall of a building.~~[50]

(f) *Extreme Weather Surveys* Where the operator has identified affected pipeline facilities through continuing surveillance per 192.613[51], leakage

[47] *See* GPAC Voting Slide # 12 – Leak Surveys and Patrols (§ 192.723). Bullet #1
"A 3-year external leak survey interval is required with consideration for the opportunity to use leak data from DIMP to extend the interval up to 5 years with appropriate agency approval. When considering approval, the appropriate agency will evaluate whether a 5-year interval would provide an equivalent or greater level of safety and environmental protection."

[48] *See* GPAC Voting Slide # 12 – Leak Surveys and Patrols (§ 192.723). Bullet #2
"Consider an alternative interval frequency for indoor piping consistent with the discussion of the GPAC."

[49] *See* GPAC Voting Slide # 13 – Leak Surveys and Patrols (§ 192.723). Bullet #1
"PHMSA consider the comments from NAPSR, other committee members, and the public on the survey frequency for indoor piping and whether leak-prone pipe includes pipelines inside of buildings and address the issues appropriately."
Associations Comment: As described previously in these comments, the Associations recommend a 5-year leak inspection interval for inside service line piping. This interval is consistent with the data and research on the inherent risk of leakage on these assets. The language proposed by the GPAC is still shown in red for PHMSA's consideration.

[50] *See* PHMSA Presentation Slide #64 – Distribution Leak Surveys – § 192.23(e)and (f).
"PHMSA concurs that investigation of known leaks following environmental changes in §192.723(e) is more appropriately addressed in the discussion of leak grading and repair, this issue will be addressed in the discussion of §192.760."

[51] *See* GPAC Transcript November 28, 2023.
Page 29. Mr. Seeley "Multiple operators in trade grade groups expressed concern that the proposed extreme weather survey requirement would be overly broad and would require a full system leakage survey after each

surveys must be performed after **an** extreme weather event~~s and land movement~~ **or natural disaster** with the likelihood to cause damage to the ~~affected~~ pipeline ~~segment~~ **facilities by the scouring or movement of the soil surrounding the pipeline or movement of the pipeline, such as a named tropical storm or hurricane; a significant flood that exceeds the river shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or a significant earthquake in the area of the pipeline.**[52] The survey must be initiated within 72 hours after the cessation of the event, defined as either the point in time when the affected area can be safely accessed by the personnel and equipment required to perform the leakage survey or when the facility has been returned to service.

event. Multiple operators commented that his requirement would be a major burden for operators as this would require a fluctuating workforce that would be difficult to hire and maintain."

Page 30. Mr. Seeley "Multiple operators in NAPSR urged PHMSA to define extreme weather event and provide examples of such events. Multiple industry representatives propose cross referencing extreme weather language in 192.613 … PHMSA intended for extreme weather to be defined as detailed in 192.613. PHMSA will clarify this in the final rule."

Page 85. Ms. Friend. "And additional patrols because of extreme weather need to be related only – need to be only to the affected areas and not the entire system."

[52] *See* PHMSA Presentation Slide #64 – Distribution Leak Surveys – § 192.723(e)and (f).
"PHMSA intended for extreme weather to be defined as detailed in §192.613. PHMSA will clarify in the final rule."

VII. Advanced Leak Detection Program (ALDP) Elements and Performance Standard

A. Discussion

1) PHMSA did not follow the cost benefit statue for ALDP

PHMSA fails to incorporate the costs for each operator to develop an ALDP in the PRIA (See Tables 19, 20 and 29). PHMSA only includes the costs for (1) updating procedures, (2) the analysis of leak detection equipment, (3) large volume release reporting, and (4) changes to annual reporting requirements. PHMSA's discussion of benefits associated with this rulemaking is narrowly focused on the "estimated the changes in methane emissions associated with accelerating the repairs of leaks through the timelier discovery of the leaks and shorter deadlines for fixing leaks" (Page 73). Therefore, PHMSA has failed to quantify any benefits beyond those realized by the prescriptive proposed requirements for leak survey intervals and leak repair timelines. No benefits have been attributed to the initial development and reevaluation of operator's ALDP. The Associations recommend PHMSA recalculate their estimate in a final regulatory impact analysis.

2) Requiring additional performance standards for ALDP, above and beyond minimum instrument sensitivity, is redundant and impractical.

The GPAC recommended comprehensive and thoughtful minimum sensitivity requirements for instruments used for leakage surveys.

As the Associations stated previously[53], applying additional performance standards to individual leakage survey instruments, above and beyond minimum sensitivity (as proposed in § 192.763(a)(1)(iii)), is redundant and impractical. PHMSA's proposal in § 192.763(a)(2)(iii) to "have procedures for validating the sensitivity of the equipment before initial use by testing with a known concentration of gas and at the required offset conditions of 5 feet" does not account for field variables such as pipeline depth of cover (or for above ground facilities, pipeline height) soil conditions, atmospheric conditions, plume behavior, and probability of detection (POD) of the equipment being used.

Operators should be free to choose any tool that meets PHMSA's minimum sensitivity, as per manufacturer specifications. For a vast majority of regulated natural gas distribution, transmission, and gathering line operators, a requirement to independently validate the tool sensitivity (above and beyond what is provided by the tool provider) would necessitate the hiring of third-party vendors to validate each instrument. This cost would be significant and would provide no tangible benefit.

In short, PHMSA should adopt a clear and unambiguous set of required instrument sensitivities and allow operators to select and use equipment that

[53] Comments On Pipeline Safety: Gas Pipeline Leak Detection and Repair; Filed by American Gas Association, American Petroleum Institute, American Fuel & Petrochemical Manufacturers, American Public Gas Association, GPA Midstream Association, Interstate Natural Gas Association of America, and Northeast Gas Association; August 16, 2023 (Docket No. PHMSA-2021-0039), pg. 93.

meets the appropriate sensitivity criteria for how they conduct leakage surveys on their systems, without requiring individual instruments to be screened against secondary performance measures that are burdensome and unrepeatable. **Therefore, the proposed requirements in §§ 192.763(a)(1)(iii)(A)-(E) and 192.763(a)(2)(iii) should be struck from the final rule.**

3) PHMSA should establish a 500 ppm alternative minimum sensitivity for instruments used in detecting leaks via continuous monitoring on non-buried pipelines, including jurisdictional inside service lines.

Many gas distribution pipeline operators have made (or are considering) extensive use of continuous leakage monitoring of inside service lines through residential Natural Gas Detectors ("NGDs"), particularly in urban environments. NGDs installed near a gas point of entry not only monitor for inside leaks on jurisdictional service piping but can also more quickly and effectively pinpoint outside gas leak sources, allowing them to be made safe and repaired promptly.

As the Associations have previously stated[54],

> *Leak investigation and survey of jurisdictional indoor piping – where the survey environment is not affected by variables such as wind/soil diffusion and gas migration patterns – is another scenario in which the fit-for-purpose detection threshold is in the percent-LEL range. Some operators have also deployed advanced fixed-sensor technologies for continuous monitoring surveys of jurisdictional indoor piping at these sensitivity thresholds. These devices and systems are designed and installed to current industry standards specified by the National Fire Protection Agency[55] and Underwriters Laboratory Standards for Safety[56] and are designated as fit-for-service to alarm at 10% LEL detection threshold and lower, with a low-end sensitivity of 1% LEL (i.e., 500 ppm).*
>
> *While it may seem counterintuitive, if the instrument threshold detection capability is too low (i.e., too sensitive), it may impede leak detection in the presence of a background combustible gas concentration at the parts per million level.*

Regarding this sensitivity, it is important to note that commercially available NGDs align with the industry standards of UL-1484 (Standards of Safety-Residential Gas Detectors). As written, PHMSA's proposal for minimum leak detection instrument sensitivity would disallow the use of most NGDs and, in conjunction with the proposed increase in frequency of leakage survey of inside piping, would disincentivize operators to deploy NGDs and other in-residence methane detection tools.

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[54] *Id.* at 90.
[55] National Fire Protection Agency, NFPA 715 Installation of Fuel Gases Detection and Warning Equipment.
[56] Underwriters Laboratories, UL 1484 Standard for Residential Gas Detectors and UL 2075 Standard for Gas and Vapor Detectors and Sensors.

The GPAC has recommended "consideration of an alternative [ALDP Performance Standard] for inside piping"[57]. A minimum sensitivity of 500 ppm (1% LEL) remains appropriate for fixed continuous monitoring sensors within buildings and is consistent with GPAC's further recommendation to establish a 500 ppm (1% LEL) minimum sensitivity for Combustible Gas Indicators (CGI).

The Associations additionally highlight that other fixed continuous monitoring devices are utilized to monitor for leaks on non-buried pipelines, predominantly inside facilities (e.g., compressor stations, LNG stations, and district regulator stations). These devices should similarly be considered for the sensitivity requirements discussed above.

4) **PHMSA should establish a 500 ppm alternative minimum sensitivity for handheld devices used for non-buried pipeline leakage surveys and leak investigations (i.e., pinpointing).**

The Committee recommended "consideration of an alternative [ALDP Performance Standard] for inside piping"[58] and the appropriateness of a 500 ppm (1% LEL) minimum sensitivity for Combustible Gas Indicators (CGIs). The Associations agree with these Committee recommendations.

PHMSA should allow for the use of CGI equipment, as it is the primary device used in the industry when performing leak investigations. CGIs are designed to take readings of percent gas-in-air during a leakage investigation, to provide leak classification readings.

Additionally, the Associations wish to highlight the differences in tools commonly used to perform leakage surveys on buried pipelines versus non-buried piping. In contrast to buried pipelines, leakage surveys of non-buried piping (i.e., the service lines located inside a building), can be performed using a handheld CGI, with probe placement close to the wall of the pipe being surveyed where readings in magnitude of percent gas-in-air are common.

5) **PHMSA should expand allowable use of OGI equipment to gas distribution pipelines.**

During the GPAC Meeting, the Committee recommended that PHMSA allow for use of optical gas imaging (OGI) equipment (meeting the requirements of 40 C.F.R. Part 60, subpart OOOO) on leakage surveys of non-buried gas transmission and gathering pipeline appurtenances. PHMSA should extend this allowance to above-ground gas distribution pipeline appurtenances.

[57] *See* GPAC Voting Slide # 17 – Advanced Leak Detection Program Elements and Performance Standards. ALDP for gas transmission and gathering lines; Bullet #4.
[58] *See* GPAC Voting Slide # 17 – Advanced Leak Detection Program Elements and Performance Standards. ALDP for gas transmission and gathering lines; Bullet #4.

6) PHMSA should allow for use of soap solution as a valid ALDP leakage survey methodology, across all assets.

As described previously in the Associations' NPRM comments[59], PHMSA should allow use of a soap solution to identify leaks on non-buried piping in the ALDP requirements. While use of a soap solution does not avail itself to prescribing a minimum sensitivity in terms of gas concentration or volumetric/mass flowrate, it is an inherently sensitive leak survey approach, and in some applications (i.e., above-ground meter sets) may be the best and most reliable method for pinpointing and grading leaks. Disallowing the use of a soap solution via a blanket minimum sensitivity requirement or impracticable performance standard is not justified and is counterproductive to enhancing pipeline safety and reducing methane emissions.

7) PHMSA should revise the scope of periodic ALDP evaluations to be consistent with the PIPES Act 2020 mandate.

As described previously in the Associations' NPRM comments[60], the Congressional mandate for evaluation of ALDP performance (as per PIPES Act 2020 Section 113) was limited. Congress directed PHMSA to set standards to "reflect the capabilities of commercially available advanced technologies" and to ensure the program is appropriate for:

(i) the type of pipeline;

(ii) the location of the pipeline;

(iii) the material of which the pipeline is constructed; and

(iv) the materials transported by the pipeline

Therefore, the scope of a formal program evaluation (and, if necessary, improvement) as per § 192.763(a)(4) should be focused on the impact (if any) of novel pipeline types, locations, materials, or media to an operator's system, and whether such changes render an operator's leakage survey equipment (or practices) deficient. Evaluation of advances in leak detection technologies and practices proposed in § 192.763(a)(4)(iii) is not required by Section 113 of PIPES Act 2020, and is irrelevant to the performance of an operator's current ALDP.

8) Layering multiple instrument types is not an appropriate method for harmonizing ALDP instrument sensitivity and leak grading criteria.

At the GPAC meeting, the Committee recommended that minimum instrument sensitivity criteria for ALDP should include a 0.5 kg/hr flowrate sensitivity for

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[59] Comments On Pipeline Safety: Gas Pipeline Leak Detection and Repair; Filed by American Gas Association, American Petroleum Institute, American Fuel & Petrochemical Manufacturers, American Public Gas Association, GPA Midstream Association, Interstate Natural Gas Association of America, and Northeast Gas Association; August 16, 2023 (Docket No. PHMSA-2021-0039), pg. 92.

[60] *Id.* at 95

gas distribution pipelines.[61] This is equivalent to a leakage rate of 24.9 scfh, which is greater than the Committee-recommended criteria for Grade 2 distribution leaks of 10 scfh.[62] The Associations acknowledge that an operator could theoretically fail to detect Grade 2 leaks between 10 scfh and 24.9 scfh despite using an ALDP-compliant instrument, although the likelihood is low that an operator would fail to identify and mitigate significant methane emissions as a result of this scenario playing out.

If PHMSA decides to address this issue in the final rule, it should not attempt to do so by requiring a second leak survey (i.e., 5 ppm instrument) to be layered on top of the flowrate-based screening survey. Such an approach would not be consistent with PHMSA's position (supported by the Committee's recommendations at the GPAC Meeting) that every leakage survey performed by ALDP-appropriate instrumentation is compliant with the associated leak survey requirements, nor is it consistent with the Committee's recommendation regarding leakage survey frequency.

Instead, the Associations recommend that PHMSA consider adopting a flowrate-based distribution ALDP sensitivity that would be capable of detecting all leaks that meet the Grade 2 criteria for environmental significant (including those between 10 and 24.9 scfh). Specifying a minimum flowrate sensitivity of 0.2 kg/hr (equivalent to 10 scfh) for gas distribution pipelines would achieve such harmonization.

9) PHMSA should remove requirements for an operator's ALDP program to include justification of the frequency by which a leak survey is performed.

49 C.F.R. §§ 192.706 and 192.723 prescribe specific leak survey frequencies for gas distribution and transmission pipelines based on several factors: leak history of the pipeline, proximity to population (i.e., Class Location for transmission pipelines), environmental factors impacting the pipeline, and whether individuals near the pipeline are aware of natural gas pipelines in the area (i.e., business districts for gas distribution pipelines). PHMSA also proposes to require the operator to justify that these prescribed frequencies are "sufficient to detect all leaks …" as per § 192.763(a)(3).
First, a standard requiring operators to "detect all leaks" is the role of the tool capability threshold, not the frequency by which the pipeline is being surveyed. Secondly, if PHMSA desires operators to leak survey some portion of their system on a more frequent basis, the agency should prescribe that in the leak survey portions of the regulation – not require operators to justify why they aren't surveying **more** frequently than what is prescribed by regulation. If PHMSA desired more frequent leak survey if an operator chooses certain tools, then that concept should have been proposed in the NPRM, commented on by

[61] *See* GPAC Voting Slide # 17 – Advanced Leak Detection Program Elements and Performance Standards. ALDP for gas distribution pipelines; Bullet #1, Sub-bullet #1.
[62] *See* GPAC Voting Slide # 22 – Leak Grading and Repair. Grade 2 leaks; Bullet #1.

the public, and discussed by the GPAC. None of those activities occurred, and therefore the Associations strongly recommend that this section be removed from the final regulation.

10) **The requirement to validate and document ALDP performance is redundant and onerous.**

As per § 192.763(a), PHMSA already proposes to require operators to meet extensive minimum instrument sensitivity requirements, as well as periodically evaluate their ALDP program to determine whether (and what) enhancements are necessary. The proposal in § 192.763(b)(1) to require validation and documentation of the ALDP program through engineering tests and analyses is redundant and unnecessary. PHMSA should not impose additional requirements to perform engineering analyses of ALDP programs, beyond what is necessary to select compliant leak detection instruments and periodically evaluate the program in § 192.763(a).

B. Updated regulatory text redline

§ 192.763 Advanced Leak Detection Program.

(a) Advanced Leak Detection Program (ALDP) Elements. Each operator must have and follow a written ALDP that includes the following elements:

(1) Leak Detection Equipment.

(i) The ALDP must include a list of leak detection equipment used in operator leakage surveys, pinpointing leak locations, and investigating leaks.

(ii) Leak detection equipment used for leakage surveys, pinpointing leak locations, investigating, and inspecting leaks must **meet the following performance standard:** ~~**have a minimum sensitivity of 5 parts per million for each gas being surveyed. The operator must validate the sensitivity of this equipment before using the device in a leakage survey by testing with a known concentration of gas.**~~

(A) For gas transmission and gathering pipelines, any one of the following:

(1) **A screening survey with a minimum sensitivity of 10 kg/hr flowrate (with a probability of detection of 90%)**[63] **and follow-up investigations of leak indications with handheld equipment with a minimum sensitivity of 5 ppm, 5 ppm-m, or 1 % LEL, or**

(2) **A leakage survey with handheld or mobile equipment with a minimum sensitivity of 5 ppm or 5 ppm-m, or**

(3) **For non-buried appurtenances, a leakage survey with a soap solution (or equivalent),**

[63] *See* GPAC Voting Slide # 16 and 17 – Advanced Leak Detection Program Elements and Performance Standards. ALDP for gas transmission and gathering lines. Bullets #2 and 3 respectively.

"Recommend Probability of Detection standard for all flow-rate based advanced leak detection technology of 90%"

non-optical continuous monitoring system (e.g., acoustical or pressure monitoring systems), handheld equipment with a minimum sensitivity of 500 parts per million (1% LEL), or Optical Gas Imaging equipment, if consistent with the requirements of Appendix K of 40 CFR part 60. [64]

(B) For gas distribution pipelines, any one of the following:

(1) A screening survey with a minimum sensitivity of 0.2 ~~0.5~~ kg/hr (with a probability of detection of 90%) flowrate and follow-up investigations of leak indications with handheld equipment with a minimum sensitivity of 5 ppm, 5 ppm-m, or 1% LEL, or

(2) A leakage survey with handheld or mobile equipment with a minimum sensitivity of 5 ppm or 5 ppm-m[65], or

(3) For non-buried appurtenances, a leakage survey with a soap solution (or equivalent), handheld equipment with a minimum sensitivity of 500 parts per million (1% LEL), or Optical Gas Imaging equipment, if consistent with the requirements of Appendix K of 40 CFR part 60, or

(4) For leakage survey within buildings, handheld equipment with minimum sensitivity of 500 parts per million (1% LEL)

(C) For fixed continuous monitoring sensors, a minimum sensitivity of 500 ppm or 500 ppm-m.[66]

(iii) Leak detection equipment must be selected based on a documented analysis considering, at a minimum, the state of commercially available leak detection technologies and practices, the size and configuration of the pipeline system, and system operating parameters and environment. ~~**At a minimum, operators must analyze the effectiveness of the following technologies for their systems:**~~

(B) ~~**The use of handheld leak detection equipment capable of detecting and locating all leaks of 5 parts per million or more when measured within 5 feet of the pipeline or within a wall-to-wall paved area, in conjunction with locating equipment to verify the tools are sampling the area within 5 feet of the**~~

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[65] *See* GPAC Voting Slide # 17 – Advanced Leak Detection Program Elements and Performance Standards. ALDP for gas distribution lines. Bullet #1.

[65] *See* GPAC Voting Slide # 17 – Advanced Leak Detection Program Elements and Performance Standards. ALDP for gas distribution lines. Bullet #1.

> "Pipeline: 0.5 kg/hr flowrate standard for screening surveys; follow up investigation of leak indications with handheld equipment (5 ppm, 5 ppm-m, or 1% LEL) to pinpoint the source of the leak, or Leakage survey with handheld or mobile equipment (5 ppm, or ppm-m)"

[66] *See* comments in section VII.A. (3) and (4) above.

~~**buried pipeline. The procedure must include sampling the atmosphere near cracks, vaults, or any other surface feature where gas could migrate;**~~

(C) ~~**Periodic surveys performed with leak detection equipment mounted on mobile, aerial, or satellite-based platforms that, in conjunction with confirmation by hand-held equipment, is capable of detecting and pinpointing all leaks of 5 parts per million or more when measured within 5 feet of the pipeline, or within a wall-to-wall paved area;**~~

(D) ~~**Periodic surveys performed with optical, infrared, or laser-based leak detection equipment that can sample or inspect the area within 5 feet of the pipeline, or within a wall-to-wall paved area, capable of detecting and pinpointing all leaks of 5 parts per million or more;**~~

(E) ~~**Continuous monitoring for leaks via stationary sensors, pressure monitoring, or other means that provide alarms or alerts and that, in conjunction with confirmation by hand-held equipment, is capable of detecting and pinpointing all leaks of 5 parts per million or more when measured within 5 feet of the pipeline, or within a wall-to-wall paved area; and**~~

(F) ~~**Systematic use of other commercially available technology capable of detecting and pinpointing all leaks producing a reading of 5 parts per million or more within 5 feet of the pipeline, or within a wall-to-wall paved area.**~~ [67] [68]

(2) Leak Detection Practices. At a minimum, an operator must have and follow written procedures for:

(ii) Performing leakage surveys required for §§ 192.706 and 192.723 using each selected leak detection technology as described in paragraph § 192.763(a)(1). The procedures must define environmental and operational conditions for which each leak detection technology is and is not permissible. The

[67] *See* GPAC Voting Slide # 18 – Advanced Leak Detection Program Elements and Performance Standards. ALDP elements. Bullet #2.

"PHMSA should provide guidance on compliance with § 192.763(a)(1)(iii), with special attention for implementation by small operators."

Note: As discussed at length by the GPAC, PHMSA has failed to present any benefits of requiring operators to justify their selection of a leakage survey tool that meets the requirements of § 192.763(a)(1)(i).

[68] *See* GPAC Transcript November 29, 2023.

Page 320. Mr. Chace "In reading and thinking about (iii), I believe that the average small to mid-size operator is going to be completely bewildered about what the expectations are for them to comply with this… The other thing in reading some of this, boy, it sure reads a whole lot like the requirements for periodic evaluation and improvement of your leak management program. So I wonder if maybe this is going a little overboard. If not, maybe the small operator exception may be appropriate for some of this. Again, we're talking about small operators that don't have R&D staff. They're not going to know what to do. Look, I got this thing and the manufacturer says it's supposed to work."

Associations Comment: The Associations recommend PHMSA remove the detailed description of what must be analyzed from § 192.763(a)(1)(iii) to align with the GPAC discussion and recommendation.

operator’s procedures must follow the leak detection equipment manufacturer’s instructions for survey methods and allowable environmental and operational parameters.

(iii) Pinpointing and investigating leaks. The location of the source of each leak indication on an onshore pipeline or any portion of an offshore pipeline above the waterline must be pinpointed and investigated with handheld leak detection equipment **(or equivalent as per § 192.763(a)(1)(ii)(A)(3))**[69]. Leak indications on offshore pipelines below the waterline may be pinpointed with human senses.

(iv) ~~**Validating that leak detection equipment meets the requirement of § 192.763(a)(1)(ii) of this section. The operator must have procedures for validating the sensitivity of the equipment before initial use by testing with a known concentration of gas and at the required offset conditions of 5 feet. Records validating equipment performance must be maintained for five years after the date the device is no longer used by the operator.**~~

(v) ~~**Maintaining and**~~ Calibrating leak detection equipment **in accordance with manufacturers recommendations.** ~~**At a minimum, procedures must follow the equipment manufacturer’s instructions for calibration and maintenance. Leak detection equipment must be recalibrated or replaced following any indication of malfunction.**~~ Records validating equipment calibration ~~**and failures indicating recalibration is necessary**~~ must be maintained for 5 years ~~**after the date the individual device is retired by the operator.**~~[70]

(3) ~~**Leakage Survey Frequency. Leakage survey frequency must be sufficient to detect all leaks that have a sufficient release rate to produce a reading of 5 parts per million or more of gas when measured from a distance of 5 feet or less from the pipeline, or within a wall-to-wall paved area, but may be no less frequent than required in §§ 192.706 and 192.723. Less sensitive equipment, challenging survey conditions, or facilities known to leak based on their material, design, or past operating and maintenance history may require more frequent surveys to detect leaks consistent with paragraph (b) of this section**~~.[71]

(4) Periodic Evaluation and Improvement. The ALDP must include procedures and records showing the operator is meeting all of the program requirements.

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[69] See GPAC Voting Slide # 19 – Advanced Leak Detection Program Elements and Performance Standards. Regarding the use of human senses and the alternative performance standard within the advanced leak detection program. Bullet #2.

“Add to § 192.763 that an operator may use human senses in addition to leak detection equipment”

[70] The Associations agree that operators must follow manufacturer’s instructions for calibration and use. As proposed, the regulatory requirement suggests that individual operators validate or verify the manufacturer’s specifications for the tool prior to each time the tool is used. This is impracticable for individual operators and it is not technically feasible to create the same control environments as the tool manufacturers. The Associations do support maintaining records of tool calibrations and support maintaining those records for 5-years.

[71] *Supra* Note 49

(ii) The operator must evaluate the ALDP at least once every three years.[72] ~~once each calendar year but with a maximum interval not to exceed 15 months.~~

(iii) The operator must make changes to any program elements necessary to locate and eliminate leaks and ~~minimize~~reduce releases of gas.

(iv) When considering changes to program elements, operators must analyze, at a minimum, the adequacy of the leakage survey procedures and any changes on the operator's system in pipeline type, location, pipeline material, or material transported by the pipeline that may affect the performance of the leak detection equipment used~~, advances in leak detection technologies and practices, the number of leaks that are initially detected by the public, the number of leaks and incidents, and estimated emissions from leaks detected pursuant to this section.~~

(v) The operator must document any changes made ~~improvements needed~~ to the program.

(b) Advanced Leak Detection Performance Standard. Each operator's ALDP described in paragraph (a) must be capable of detecting all leaks that have a sufficient release rate to produce a reading of 5 parts per million or more of gas ~~when measured from a distance of 5 feet or less from the pipeline~~, or within a wall-to-wall paved area.

~~(1) The performance of the ALDP must be validated and documented with engineering tests and analyses.~~

(2) ~~Records validating that the~~ ALDP records ~~meets the performance standard~~ must be maintained for at least 5 years after the date that ALDP is no longer used by the operator.

(c) Alternative Advanced Leak Detection Performance Standard. ~~For gas pipelines other than natural gas pipelines, and for natural gas transmission, offshore gathering, and Types A, B, and C gathering pipelines located in Class 1 or Class 2 locations,~~[73] An operator may use an alternative ALDP performance standard (and supporting leak detection equipment) with prior notification to, and with no objection from, PHMSA in accordance with § 192.18. PHMSA will only approve a notification if operator, in the notification, demonstrates that the alternative performance standard is consistent with pipeline safety and equivalent to the standard in ~~(b)~~ (a)[74] for reducing greenhouse gas emissions and other environmental hazards. The notification must include:

(1) Mileage by system type;

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[72] *See* GPAC Voting Slides # 18 – Advanced Leak Detection Program Elements and Performance Standards. ALDP program elements. Bullet #1.

"The committee recognizes that periodic evaluation and continuous improvement is necessary and recommends PHMSA consider requiring an operator conduct an evaluation every 3 years to ensure the adequacy of the leak detection program"

[73] *See* GPAC Voting Slides # 16 and 17 – Advanced Leak Detection Program Elements and Performance Standards. ALDP for gas transmission and gathering lines. Bullets #1 and 3.

"Clarify that the scope of the alternative performance standard process in §§ 192.18 and 192.763(c) covers all gas transmission and regulated gas gathering pipelines, and

Clarify that the scope of the alternative performance standard process in §§ 192.18 and 192.763(c) covers gas distribution pipelines."

[74] The Associations believe it was PHMSA's intent to reference subsection (a), not (b), in this instance.

(2) Known material properties, location, HCAs, operating parameters, environmental conditions, leak history, and design specifications, including coating, cathodic protection status, and pipe welding or joining method;
(3) The proposed performance standard;
(4) Any safety conditions, such as increased survey frequency;
(5) The leak detection equipment, procedures, and leakage survey frequencies the operator proposes to employ;
(6) Data on the sensitivity and the leak detection performance of the proposed alternative ALDP standard; and
(7) The gas transported by the pipeline.

VIII. Leak Grading and Repair

A. Discussion

1) PHMSA should reiterate that the leak grading regime proposed by § 192.760 is not retroactive to grading of leaks under operator- and state-defined grading criteria prior to the compliance date.

PHMSA proposes to introduce a repair schedule for leaks found on or before the effective date of the final rule that were graded using an operators' grading criteria or one prescribed by a state level regulation. These leaks are also likely to be on an operator-defined schedule for *reevaluation* that may be different than PHMSA's proposed reevaluation schedule in § 192.760.

It is unreasonable to retroactively apply grading requirements in § 192.760 to leaks known by operators to exist prior to the compliance date of the rule, a reality that was acknowledged in the GPAC discussion[75].

2) PHMSA should explicitly exempt gas distribution pipeline operators from screening leaks against the proposed Grade 1 "environmental hazard" criteria.

The GPAC voted to recommend a 100 kg/hr estimated leakage rate criterion for "environmentally hazardous" leaks. Leaks meeting or exceeding this leakage rate threshold would automatically be graded as Grade 1 leaks under § 192.760(b).

As GPAC member Dr. Ravikumar made clear[76], an estimated leakage rate of 100 kg/hr or above is unknown on gas distribution systems. Given that the largest leakage rates on gas distribution pipeline fall far below this criterion, PHMSA should explicitly exempt gas distribution leaks from this specific Grade 1 leak criterion. Absent such an exemption, gas distribution pipeline operators would be forced to screen every leak against the 100 kg/hr criterion and prove that the smallest of leaks do not exceed that threshold before a lower leak grade (i.e., Grades 2 or 3) could even be considered. Such screening would

[75] *See* GPAC Transcript November 30, 2023.
Pages 269-270.
Ms. Gosman "…Are you expecting that operators would regrade their existing leaks, based on the current criteria? Or are they using the legacy criteria? I know there's a lot of overlap, but I just want to understand the issue."
Mr. Mayberry "Yes, Sara, I don't anticipate operators would regrade."
Mr. Zamarin "…I just want to make sure I understand this right. So, are you saying, Alan, that this is a requirement for the operator repair timelines for existing leaks that they've graded under their existing grading scheme, and they do not have to update those gradings for this new regulation?"
Mr. Mayberry "That's correct. That's how it is."

[76] *See* GPAC Transcript November 30, 2023.
Pages 93-94.
Mr. Ravikumar "….what I would say is that, you know, 100 kilograms per hour is so large that we have, in all of the studies that have been conducted, we have never seen a leak that large in the distribution system. In fact, we have never seen a leak that is ten kilograms per hour in the distribution system. So it's automatically going to exclude the entire distribution system if we are thinking of very large leaks."

be both unnecessary and unreasonable, with no benefit to pipeline safety or emissions mitigation.

3) PHMSA should not describe Grade 2 leaks as posing a "significant harm to the environment."

As described in previous comments submitted by the Associations[77], describing Grade 2 leak as posing "significant harm to the environment" is a mischaracterization. As PHMSA stated during the GPAC meeting, the descriptors used in § 192.760 are not intended to add criteria to the leak grading requirements. Therefore, the Associations recommend deleting these phrases since they are undefined and there is no consensus on their use.

4) PHMSA should remove redundancies in the regulation pertaining to the repair of Grade 2 leaks.

The Committee supported PHMSA's proposal to require operators to develop a methodology for prioritizing the repair of Grade 2 leaks and to document this methodology within their operations and maintenance procedures. GPAC also recommended a schedule for repairing Grade 2 leak repairs "as soon as practicable, considering impacts to customers and environmental concerns, but not to exceed 1 year."

Together, these two recommendations make redundant and conflict with PHMSA's proposal to prioritize certain Grade 2 leaks for repair within a prescribed 30-day schedule (as per § 192.760(c)(4)). Additionally, mandating a 2-week reevaluation schedule for these "priority" Grade 2 leaks in § 192.760(c)(4) is also redundant and unnecessary.

PHMSA should strike the 30-day repair and 2-week reevaluation schedule requirements from § 192.760(c)(4), and instead only require a 2-week reevaluation of Grade 2 leaks on gas transmission or gathering pipelines located in HCA, Class 3, or Class 4 locations, as per § 192.760(c)(3).

5) PHMSA should allow for extensions to Grade 2 leak repair schedules via notification to the appropriate agency.

PHMSA proposes to allow operators to request an extension to the leak repair deadlines for Grade 3 leaks with "advance notification to and no objection from" the appropriate agency, using the notification process prescribed in § 192.18. This is an important recognition of potential barriers to meeting the established leak repair schedule, including impracticability of the repair, potential risk or impact to public safety, and scenarios in which repairing the leak by a date certain will result in more greenhouse gas emissions than continuing to monitor the leak. For example, the identification of a Grade 2 leak underwater or a beneath a roadway will take significant planning and coordination with entities

[77] Comments On Pipeline Safety: Gas Pipeline Leak Detection and Repair; Filed by American Gas Association, American Petroleum Institute, American Fuel & Petrochemical Manufacturers, American Public Gas Association, GPA Midstream Association, Interstate Natural Gas Association of America, and Northeast Gas Association; August 16, 2023 (Docket No. PHMSA-2021-0039), pg. 149.

outside the control of the pipeline operator. In some scenarios permitting will be required, which can take months, if not years, to obtain.

PHMSA should therefore also allow operators to request an extension to the repair deadline for Grade 2 leaks, given that some scenarios in which it may be appropriate to delay the repair of a leak are no different to that of Grade 3 leaks.[78] In any case, the measures to mitigate the additional risk of Grade 2 leaks (relative to Grade 3) are already accounted for in the accelerated repair schedule, the GPAC recommendation to prioritize and repair as soon as practicable, and narrower repair schedule exemptions for leaks eliminated through future replacement projects. In short, if Grade 2 leaks otherwise meet the criteria proposed in § 192.760(h), an extension to their repair schedule should be allowed.

Furthermore, PHMSA should consider creating parity with EPA's OOOOa final rule which also includes technical feasibility, blowdown, compression shutdown, and safety considerations, in addition to parts availability, as reasons to extend repairs beyond 30 days.[79]

PHMSA should also consider the suitability of using § 192.18 notifications for extensions to leak repair schedules, given that such notifications are expected to be made "at least 90 days in advance," which does not comport with the 30-day repair schedules proposed by PHMSA in this rule (i.e., § 192.760(c)(3)). For these scenarios, PHMSA should explore means of exempting operators from the § 192.18 notification process, or alternatively allow for the 30-day repair schedule to begin from the date PHMSA issues a no-objection letter or takes other actions in response to a § 192.18 notification. Moreover, PHMSA should consider how such an alternative to the § 192.18 notification process/timeline could be applied to other portions of this rule.

6) **PHMSA should recognize that operators may perform investigation of Grade 2 leaks affected by weather changes in the course of executing other weather-related O&M activities.**

PHMSA proposes to require operators to investigate Grade 2 leaks following a weather-related change (e.g., freezing ground, heavy rain, flooding, or other changes) that could affect the migration of gas from the Grade 2 leaks. In promulgating a final rule, PHMSA should acknowledge that operators may perform such investigations as part of a written program to evaluate weather-related changes to its system (i.e., dedicate frost-related leak surveys), and that these program-level activities are suitable for investigating Grade 2 leaks, especially given the erratic nature of weather changes.

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[78] PRIA at 64. "PHMSA estimated that it may receive 1,000 requests per year to extend the deadline for remedying leaks on distribution lines, with each of these requests requiring approximately 8 hours to prepare (PHMSA BPJ). This number is approximately 5 percent of the total number of grade 3 leaks PHMSA estimated to be discovered each year using LDAR methods. This is likely an upper bound estimate given the additional costs involved and operators would only seek an extension if they are unable to make the repair."

[79] https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-OOOOa/section-60.5397a.

7) **PHMSA should give operators flexibility in prioritizing Grade 2 leaks for repair based on emissions considerations.**

PHMSA proposes to require operators to consider "volume…of gas emissions" as one of the criteria for prioritizing repair of Grade 2 leaks as per § 192.760(c)(4)(i). Strictly limiting the environmental considerations to strictly emissions volume is not appropriate, given the difficulty of estimating emissions volumetrically while the leak is still active, as well as the reality that some operators will be grading the leaks in question using leak extent or an alternative methodology. In any case, the volumetric emissions at the time of repair prioritization *have already occurred*, and may not be reflective of the avoided emissions that an operator may wish to consider. PHMSA should give operators wide latitude to determine how to consider emissions in prioritizing the repair of Grade 2 leaks.

8) **PHMSA should not mandate a process for operators to prioritize Grade 3 leak repairs.**

Although the Associations acknowledge the rationale (and precedent, as per GPTC guidance) for requiring a written methodology for prioritizing repair of Grade 2 leaks, PHMSA was correct to not propose mandating such a methodology for Grade 3 leak repairs within the NPRM.

The GPAC's recommendations will ensure that higher-emitting Grade 3 leaks (e.g., ≥ 5 scfh or equivalent) will be subject (with limited exceptions) to a 36-month repair schedule, which is more stringent than any previous GPTC guidance, and moreover goes beyond the Congressional mandate for leak repair in Section 113 of the PIPES Act 2020 (which exempts from a prescribed repair schedule "a leak so small that it poses no potential hazard"). Requiring operators to further develop and follow a written methodology for evaluating Grade 3 leaks for accelerated repair is onerous and unnecessary.

The Associations also question the utility of further prioritizing the repair schedule of these small leaks. The leak grading criteria is in and of itself a prioritization of repairs. Operators also inherently prioritize their repairs across multiple factors, including risks to the public, proximity to other pipeline construction projects, and alignment with street work occurring near the pipeline. Requiring operators (of all sizes and capabilities) to further document this individualized prioritization process would not only be very onerous, but would not deliver tangible pipeline safety benefits.

9) **PHMSA should make clear that the criteria for evaluating environmental significance of Grades 2 and 3 leaks are a *choice of methods,* and the use of *any one method* meets the intent of the regulation.**

In previous comments to the NPRM, the Associations proposed a multi-method set of criteria against which the environmental significance of graded leaks could be evaluated. This was in contrast to PHMSA's blanket 10 scfh criterion for Grade 2 leaks, as proposed in § 192.760(c)(1)(vii)[80]

[80] NPRM at 31976.

The Committee supported a version of the Associations' multi-method approach[81], including evaluating leaks based on (1) estimated leakage rate in scfh, (2) leak extent (in square feet) of underground leaks, and (3) alternative methods, with notification to the appropriate agency as per § 192.18. This multi-method approach necessarily allows operators to determine the environmental significance of a leak in a manner that is appropriate for their system, available technology, and purchased leak detection equipment that meets the specifications of § 192.763(a) and not mandating use of a methodology based on estimated leakage rate.

However, in order to codify this necessary flexibility, PHMSA must make it clear within §§ 192.760(c)-(d) that operators are required to apply to only <u>one</u> of the available methods in determining the environmental significance of a Grade 2 or 3 leak. If this is not made sufficiently clear, PHMSA may inadvertently require operators to screen every leak against all available criteria, so that (for example), before a leak could be graded as Grade 3 it would have to be shown to be below the Grade 2 leakage rate threshold (in scfh), *and* below the Grade 2 leak extent threshold (in square feet), *and* below any Grade 2 leak thresholds established through an alternative method. Such a multi-tiered screening process would be onerous, impractical, and in complete opposition of the intent to provide flexibility in evaluating the environmental significance of a leak.

10) A menu of the methods should be available to operators for evaluating the environmental significance of Grade 3 leaks.

The GPAC also recommended establishing a similar set of thresholds for environmental significance of Grade 3 leaks, below which leaks would be exempted from a defined repair schedule § 192.760(d).

It is appropriate that the criteria used to screen Grade 3 leaks for environmental significance is parallel to the multi-method set of criteria established for Grade 2 leaks in § 192.760(c). The GPAC recognized the importance of allowing a menu of methods to make this determination for Grade 3 leaks but declined to recommend a specific threshold (in square feet) for the leak extent method, absent additional clarity on how leak extent scales relative to leakage rate (in scfh).

The original recommendation to accelerate repair of leaks with a leak extent of 2,000 square feet or more, previously adopted by the State of Massachusetts[82]

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[81] *See* GPAC Voting Slides #22 & 26 – Leak Grading and Repair.

Slide # 22, Bullet #2.

"Is of sufficient magnitude to pose significant harm to the environment, considering *one of the following characteristics*"

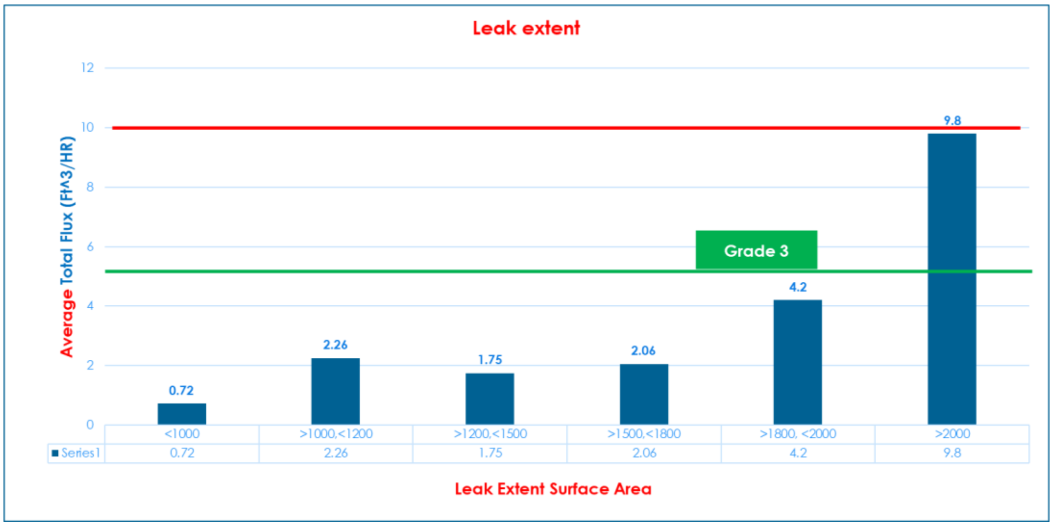
Slide #26, Bullet #5

"Repair is required for grade 3 gas distribution pipelines with an emissions rate greater than or equal to 5 scfh, *or* a leak extent method equivalent to 5 scfh, *or* an alternative method demonstrated to meet the capability of identifying a minimum leakage rate of 5 scfh with a notification to PHMSA in accordance with Sec. 192.18."

[82] Pipeline Safety: Gas Pipeline Leak Detection and Repair, 88 Fed. Reg. at 31919.

and recommended for incorporation into § 192.760(c) by the GPAC[83], is based on the 2017 Large Volume Leak Study[84]. This study is more fully described in the paper "Identifying and Rank-Ordering Large Volume Leaks in the Underground Natural Gas Distribution System of Massachusetts,"[85] a 2018 Harvard University study by Zeyneb Magavi.

Ms. Magavi's study found the emissions of a leak are strongly correlated with the leak extent, or size of the gas-saturated surface area over the leak. The study's raw data suggested that a measured emissions rate of between 4 and 5 scfh is consistent with a leak extent area of approximately 1,800 square feet (see figure below, as graphed by the Associations). It is therefore appropriate to adopt an 1,800 square feet leak extent for Grade 3 leaks to go along with the GPAC-recommended 5 scfh leakage rate (and alternative).



11) **PHMSA should harmonize timing of leak repair completion with its own understanding of when post-repair leak re-checks are needed.**

PHMSA acknowledged[86] during the GPAC Meeting that the primary scenario in which post-repair leak re-checks (as proposed in § 192.760(e)) are

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[83] *See* GPAC Voting Slide #22 – Leak Grading and Repair.
Slide # 22, Bullet #4.

[84] "Large Volume Leak Study," 2017. Home Energy Efficiency Team. https://heet.org/gas-leaks/large-volume-leak-study/

[85] Magavi, Zyneb Pervane. "Identifying and Rank-Ordering Large Volume Leaks in the Underground Natural Gas Distribution System of Massachusetts." 2018. https://dash.harvard.edu/handle/1/37945149

[86] *See* GPAC Transcript December 1, 2023.
Pages 27-29.
Mr. Weisker "….the way this provision is written from how onerous, an operator must conduct a post-repair inspection at least days but no later than 30 days after the date of repair to determine if the repair is complete. So every single repair we do, we're now rolling another truck to go on out, to reinspect what we inspected at the beginning of the process. We inspected it. We found a leak. We've repair it. We validate that the repair is fixed. And then we're doing a whole other re-roll of a truck. …. This would be a significant amount of truck rolls and effort, resource time going to just validate what we validated 14 days before. And I just don't think to me that makes -- it just doesn't make sense. Let's take those resources and put them to use to fixing other Grade

necessary is to verify there are no *other leaks* in the vicinity of the repaired leak that the operator may not have identified during the initial leak investigation. The Associations support this recognition, and it reflects the joint comments to the NPRM, which stated that:

> *scenarios in which residual gas readings do not decline are not evidence a repair was inadequate. These persistent readings can be indicative of another leak (or leaks), which may even have occurred after the initial repair was made. Accordingly, the provision stating that a repair is not "complete" until 0% gas readings are achieved is not valid and may create misinterpretations for demonstrating compliance with repair intervals prescribed in § 192.760.*[87]

Consistent with the agency's own stated position, PHMSA should ensure that the timing of the "repair completion" in § 192.760 is based on the conclusion of the repair event and is not contingent on achieving a 0% gas reading during the subsequent leak repair re-check.

12) PHMSA should further evaluate existing State regulations related to leak grading based on proximity to buildings and structures.

The Associations recognize PHMSA's logic in proposing leak classification action criteria from GPTC Guidance, more specifically codifying GPTC criteria from Guide Material Appendix G-192-11. However, it does not consider GPTC guidance which addresses the critical nature of leak indications relative to the proximity of a building or structure in the grading process. The examples cited by GPTC do not define this variable. As discussed at the GPAC Meeting, several States *have* adopted leak grading criteria that consider proximity to building or a structure[88]. These additional criteria have provided operators an alternate means of prioritizing certain leaks (via grading), particularly in wall-to-wall paved areas. The Associations encourage PHMSA consider how proximity criteria might be adopted as an alternative grading scheme for leaks in wall-to-wall paved areas. An example of such a proximity-based leak grading approach is shown in Appendix A.

Alternatively, PHMSA should consider allowance for an operator to follow State-approved leak grading and repair requirements, if and where the existing State-approved leak grading process provides an equal or greater overall level of safety and emissions mitigation.

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3 leaks versus going out to reinspect what we did 14 days before that we inspected on the day when we did the work."

Mr. Mayberry "…a vast majority may be that way but what about say the situation where you may have multiple leaks. You repair one, but it may be -- and you have gas migration that varies, you know, greatly whether you're dealing with sandy soil or clay soil that may be coming from a totally different location. So, you know, there are -- as we work to establish a national minimum standard, you know, we've got to be able to address the fact that you may not have gotten it."

[87] Comments On Pipeline Safety: Gas Pipeline Leak Detection and Repair; Filed by American Gas Association, American Petroleum Institute, American Fuel & Petrochemical Manufacturers, American Public Gas Association, GPA Midstream Association, Interstate Natural Gas Association of America, and Northeast Gas Association; August 16, 2023 (Docket No. PHMSA-2021-0039), pg. 72.

[88] *See* Comments by the Northeast Gas Association submitted to Docket No. PHMSA-2021-0039, August 16, 2023.

Finally, for purposes of this NPRM, PHMSA should consider adopting gas-in-air units when describing gas leak concentrations. Given the variability of lower explosive limit (LEL) values of gas, using gas-in-air rather than percent-LEL will ensure a more consistent approach to conformance with requirements based in gas concentrations.

B. Updated regulatory text redline

§ 192.760 Leak grading and repair.

(a) General. Each operator must have and follow written procedures for grading and repairing leaks that meet or exceed the requirements of this section.

(1) These requirements are applicable to leaks on all portions of a gas pipeline including, but not limited to, line pipe, valves, flanges, meters, regulators, tie-ins, launchers, and receivers.

(2) The leak grading and repair procedure must prioritize leaks by the hazard to public safety and the environment.

(3) Each leak must be investigated immediately ~~**and continuously**~~ ~~**until**~~ **and** a leak grade determination ~~**has been**~~ **must be** made **as part of that investigation**.

(b) Grade 1 leaks.

(1) A grade 1 leak is ~~**any leak that constitutes an existing or probable hazard to persons or property or a grave hazard to the environment. A grade 1 leak includes**~~[89] a leak with any of following characteristics:

(i) **a hazardous leak** ~~**any leak that, in the judgment of operating personnel at the scene is regarded as an existing or probable hazard to public safety or a grave hazard to the environment**~~;

(ii) **a leak on a gas transmission or gathering pipeline with a leakage rate greater than or equal to 100 kg/hr;**[90]

(iii) any amount of escaping gas has ignited;

(iv) any indication that gas has migrated into a building, under a building, or into a tunnel;

(v) any **below-grade** reading of gas at the outside wall of a building, or areas where gas could migrate to an outside wall of a building;

(vi) any reading of 80% or greater of the LEL (60% for LPG systems) in a confined space;

(vii) any reading of 80% or greater of the LEL (60% for LPG systems) in a substructure, (including gas associated substructures) from which any gas could migrate to the outside wall of a building;

(viii) any leak that can be seen, heard, or felt**, and which is in a location that may endanger the general public or property**;[91] or

(ix) any leak defined as an incident in § 191.3.

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[89] *See* PHMSA Presentation Slide #131 – Leak Grading – §§ 192.703 and 760.
"PHMSA notes that the introductory language was intended to be descriptive and not an actionable grading criteria."

[90] *See* GPAC Voting Slide # 21 – Leak Grading and Repair. Grade 1 Criteria. Bullet #2.
"The GPAC recommends PHMSA clarify the meaning of grave environmental hazard or provide more clarity on what conditions pose a grave environmental hazard. Modify the Grade 1 leak criteria to include those leaks equal to or greater than 100 kg/hr."

[91] *See* GPAC Voting Slide # 21 – Leak Grading and Repair. Grade 1 Criteria. Bullet #1.
"Clarify the 'seen, heard, or felt criteria' (b)(1)(vii) consistent with GPTC guide language."

(2) An operator must promptly repair a grade 1 leak and eliminate the hazardous conditions by taking immediate and continuous action by operator personnel at the scene. Immediate action means the operator will begin instant efforts to remediate and repair the leak upon detection and to eliminate any hazardous conditions caused by the leak. Continuous means that the operator must maintain ~~**on-site**~~ remediation efforts until the leak **has been made safe through repair or isolation to stop flow of the leak**. This may require one or more of, but not limited to, the following actions be taken without delay:

- (i) implementing an emergency plan pursuant to 49 CFR § 192.615;
- (ii) evacuating premises;
- (iii) blocking off an area;
- (iv) rerouting traffic;
- (v) eliminating sources of ignition;
- (vi) venting the area by removing manhole covers, bar holing, installing vent holes, or other means;
- (vii) stopping the flow of gas by closing valves or other means; or
- (viii) notifying emergency responders.

(c) Grade 2 leaks.

(1) A grade 2 leak ~~**constitutes a probable future hazard to persons or property or a significant hazard to the environment, and**~~[92] includes any leak (other than a grade 1 leak) with any the following characteristics:

- (i) a reading of 40% or greater of the LEL under a sidewalk in a wall-to-wall paved area that does not qualify as a grade 1 leak;
- (ii) a reading at or above 100% of LEL under a street in a wall-to-wall paved area that has gas migration and does not qualify as a grade 1 leak;
- (iii) a reading between 20% and 80% of the LEL in a confined space;
- (iv) a reading less than 80% of the LEL in a substructure (other than gas associated substructures) from which gas could migrate;
- (v) a reading of 80% or greater of the LEL in a gas associated substructure from which gas could not migrate;
- **(vi)** ~~**any reading of gas that does not qualify as a grade 1 leak that occurs on a transmission pipeline or a Type A or Type C regulated gas gathering line;**~~
- (vii) **a leak on a gas distribution pipeline meeting** ~~**of sufficient magnitude to pose significant harm to the environment, based on**~~ **any one of the following methods as determined by the operator:**:
  - **(A)** ***if evaluating by leakage rate:*** **any leak with an estimated leakage rate of 10 cubic feet per hour (CFH) or more, or**
  - **(B)** ***if evaluating by belowground and subsurface leak extent:*** **an estimated leak extent (land area affected by gas migration) of 2,000 square feet or greater, or**
  - **(C)** ***if evaluating by alternative methods:*** **a leak identified using an alternative method, with advance notification to and no objection from PHMSA pursuant to § 192.18. The operator's**

[92] *See* PHMSA Presentation Slide #131 – Leak Grading – §§ 192.703 and 760.
"PHMSA notes that the introductory language was intended to be descriptive and not an actionable grading criteria.

notification must show that the alternative method is capable of identifying a leakage rate of 10 cubic feet per hour.[93]
~~that does not qualify as a grade 1 leak;~~

(viii) **~~Any leak of LPG or hydrogen gas that does not qualify as a grade 1 leak; or~~**

(ix) any leak that, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair within **twelve** **~~six~~** months or less.

(x) **any leak on a gas transmission or gathering line with any of the following characteristics:**

(A) **occurs on the pipe body on a pipeline operating greater than or equal to 30% SMYS**

(B) **a leak with a leakage rate greater than or equal to 10 kg/hr.**[94]

(2) An operator must schedule repair based on the severity or likelihood of hazard to persons, property, or the environment. A grade 2 leak must be repaired **as soon as practicable with consideration for customer impacts and environmental concerns. The repair timeline must not exceed** **~~within~~** **twelve** **~~six~~** **months**[95] **from the date** of detection, unless a shorter repair deadline is required by the operator's procedures, integrity management program, or paragraphs (c)(3)-(6) of this section. The operator must re-evaluate each grade 2 leak at least once every **6 months** **~~30 days~~**[96] until it is repaired.

(3) The operator must complete repair of any grade 2 leak on a gas transmission or Type A gathering pipeline, each located in an HCA, Class 3 or Class 4 location, within 30 days of detection. If repair cannot be completed within 30 days due to permitting requirements or parts availability, the operator must take continuous action to monitor and repair the leak. **Grade 2 leaks on a gas transmission or Type A gathering pipeline with a repair deadline of less than or equal to 30 days must be re-evaluated at least once every 2 weeks until the repair is complete.**[97]

(4) Each operator's operations and maintenance procedure must include a methodology for prioritizing the repair of grade 2 leaks**~~, including criteria for leaks that warrant repair within 30 days of detection pursuant to § 192.760(c). Grade 2 leaks with a repair deadline of less than 30 days must be re-evaluated at least once every 2 weeks until the repair is complete~~**.[98] This methodology must include an analysis of, at a minimum, each of the following parameters:

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[93] *See* GPAC Voting Slide # 22 – Leak Grading and Repair. Grade 2 Criteria. Bullet #1.
"Distribution: 10 scfh and leak extent criteria"

[94] *See* GPAC Voting Slide # 22 – Leak Grading and Repair. Grade 2 Criteria. Bullet #2.
"Transmission and gathering: modifying grade 2 leak requirements to include:…"

[95] *See* GPAC Voting Slide # 23 – Leak Grading and Repair. Grade 2 repair timelines. Bullet #1.
"Repair grade 2 leaks as soon as practicable considering impacts to customers and environmental concerns, but not to exceed one year."

[96] *See* GPAC Voting Slide # 25 – Leak Grading and Repair. Reevaluation frequency for grade 2 leaks.
"Revise the reevaluation frequency for grade 2 leaks to a 6-month interval."

[97] *See* GPAC Voting Slide # 24 – Leak Grading and Repair (§ 192.760(c)(4)). Bullet #2.
"Move the 2 week recheck for repairs within a 30-day repair timeline to (c)(3)."

[98] *See* GPAC Voting Slide # 24 – Leak Grading and Repair (§ 192.760(c)(4)). Bullet #1.
"Revise the introductory text paragraph to read as follows:…"

(i) ~~volume and migration of gas emissions;~~**significance of emissions, as determined by the operator;**

(ii) the proximity of gas to buildings and subsurface structures;

(iii) the extent of pavement; and

(iv) soil type and conditions, such as frost cap, moisture, and natural venting.

(v) **Impact to customers and alignment with possible outages to minimize emissions to leak repairs**

(5) **Following a weather-related change that could affect gas migration (e.g., freezing ground, heavy rain, flooding, or other changes) e**ach operator must ~~take immediate and continuous action to complete~~ **investigate** ~~repair of a~~ grade 2 leak**s** and eliminate ~~the~~ hazard**s** **identified in the investigation**. **This investigation may be made in the course of an operator's written program to evaluate weather-related impacts to its system.** ~~when freezing ground, heavy rain, flooding, new pavement, or other changes to the environment are anticipated or occur near an existing grade 2 leak that may affect the venting or migration of gas and could allow gas to migrate to the outside wall of a building~~.[99]

~~(6) An operator must complete repair of known grade 2 leaks existing on or before [insert effective date of the final rule] before [insert date 1 year after the publication[100] date of the final rule].~~

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[99] *See* GPAC Voting Slide #28 – Investigation or repairs of leaks following environmental changes.

"PHMSA consider a risk-based approach for the repair of grade 2 leaks following environmental changes that affect gas migration (e.g. freezing ground, heavy rain, flooding, or other changes).

Provide for consideration of local safety and environmental conditions."

[100] *See* GPAC Transcript November 30, 2023.

Page 266. Mr. Drake "I think I just have a question to PHMSA here on the practical aspect of this as far as implementation. This is requiring operators to start fixing things they knew about once the rule is published. But we haven't really even talked yet about what is the implementation schedule. So if the implementation schedule moves out to coordinate with EPA, let's say, we would start fixing things before the rule actually implemented. Is that kind of what this would mean, in essence?"

Mr. Gale "No, I think we would have to coordinate that, right? Obviously you can't get in front of the effective date of the overall rule. And I think we would have to look at each of these components, you know, and their given situation and how they apply."

Mr. Drake "Because the thing that's catching my attention is implementation – or published versus implementation. And if we said implementation, maybe what would make some sense. But when we say published, when the rule can be published in six months, but it may not be implemented for a while--- and then, we've got our cart and our horse out of order again. I don't mean to get into semantics but it's actually quite important."

Mr. Ariaratnam "You know, regardless of whether it's 36 months or 26 months, maybe it should instead of after the date of publication, kind of what you were saying Andy, would be maybe after the effective date of the final rule. That's what I think. That would be more fair to all parties."

Page 274. Mr. Ariaratnam "So, I'm going to put the proposal in of 12 months after the effective date of the final rule."

Mr. Weisker "I could support what Sam just proposed. I think that's a good approach, 12 months after the effective date of the final rule."

Ms. Gosman "Yes, I think Sam's proposal is very good. I'll just note that we're going to have, I think, a discussion about the effective date of the final. And I think it will be important at that point to remember that this particular provision is tied to that effective date."

(7) A grade 2 leak may be evaluated in accordance with paragraph (c)(2) of this section and repairs postponed if the segment containing the leak is scheduled for replacement, and is replaced, within two years of detection of the leak.[101]

(d) Grade 3 leaks.

(1) A grade 3 leak is any leak that does not meet the criteria of a grade 1 or grade 2 leak. In order to qualify as a grade 3 leak, none of the criteria for grade 1 or 2 leaks must be present. Grade 3 leaks may include, but are not limited to, leaks with the following characteristics:

(i) a reading of less than 80% of the LEL in gas associated substructures from which gas is unlikely to migrate; or

(ii) any reading of gas under pavement outside of a wall-to-wall paved area where gas is unlikely to migrate to the outside wall of a building; or

(iii) a reading of less than 20% of the LEL in a confined space.

(2) A grade 3 leak must be repaired within ~~24~~ 36[102] months of detection, except as described below:

(i) A grade 3 leak known to exist on or before [insert effective date of the final rule] must be repaired prior to [insert date 3 years after the ~~publication~~ effective date of the final rule].

(ii) A grade 3 leak may be evaluated in accordance with paragraph (d)(3) of this section and repairs postponed if the segment containing the leak is scheduled for replacement, and is replaced, within ~~five~~ seven[103] years of detection of the leak.

(iii) A Grade 3 leak meeting criteria based on any one of the following methods, as determined by the operator, is exempted from a repair schedule:

(A) *If evaluating by leakage rate:* any leak with a estimated leakage rate of 5 cubic feet per hour (CFH) or less, or

(B) *if evaluating by belowground/subsurface leak extent:* an estimated leak extent (land area affected by gas migration) of 1,800 square feet or less, or

(C) *if evaluating by alternative methods:* a leak identified as being of equivalent magnitude using an alternative method, with advance notification to and no objection from PHMSA pursuant to § 192.18. The operator's notification must show that the alternative method is capable of identifying a leakage rate of 5 cubic feet per hour.[104]

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[101] *See* GPAC Voting Slide # 23 – Leak Grading and Repair. Grade 2 repair timelines. Bullet #2. "Exception for distribution pipelines scheduled for replacement and is replaced within 2 years."

[102] *See* GPAC Voting Slide # 26 – Leak Grading and Repair. Grade 3 criteria and repair timelines. Bullet #1A. "Repair timeline: Revise general repair timeline from 24 months to 36 months"

[103] *See* GPAC Voting Slide # 26 – Leak Grading and Repair. Grade 3 criteria and repair timelines. Bullet #2. "Grade 3 criteria: "… Repair is required within 36 months, unless the pipeline is scheduled for replacement and replaced within 7 years..."

[104] *See* GPAC Voting Slide # 26 – Leak Grading and Repair. Grade 3 criteria and repair timelines. Bullet #2. "Grade 3 criteria: Repair is required for grade 3 gas distribution pipelines with an emissions rate greater than or equal to 5 scfh, or a leak extent method equivalent to 5 scfh, or an alternative method demonstrated to meet the capability of identifying a minimum leakage rate of 5 scfh with a notification to PHMSA in accordance with Sec. 192.18."

(iv) A grade 3 leak on transmission pipeline in an HCA, Class 3 or Class 4 area must be repaired within 12 months of detection.[105]

(3) Each operator must re-evaluate each grade 3 leak at least once every ~~six~~ twelve months until repair or remediation of the leak is complete.[106]

(e) Post-repair ~~inspection~~ re-check.[107]

~~(1) A leak repair is considered to be complete when an operator obtains a gas concentration reading of 0% gas at the leak location after a permanent repair.~~

(2) An operator must conduct a post-repair leak ~~inspection~~ re-check after allowing the soil to vent and stabilize, ~~at least 14 days after~~[108] ~~but~~ no later than 30 days after the date of the repair to determine if the repair was complete.

(3) If a post-repair ~~inspection~~ re-check shows a gas concentration reading greater than 0% gas, the ~~repair is not complete, and~~ operator must take the following actions:

~~(i)~~ If the post repair ~~inspection~~ re-check finds gas concentrations lower than the most recent read, the operator must perform a re-check within 30 days and continue re-checking at least once every 30 days until there is a gas concentration reading of 0% ~~or migration indicating that the potential for a grade 1 or grade 2 condition leak exists, the operator must re-inspect the repair and take immediate and continuous action to eliminate the hazard and complete repair;~~

(ii) If the ~~operator's~~ post repair ~~inspection~~ re-check ~~does not~~ finds a gas concentration reading equal to or higher than the most recent re-check reading ~~of 0% at the leak location, and a grade 1 or grade 2 condition does not exist,~~ then the operator must investigate ~~remediate~~ and repair or grade the leak according to paragraph (b), (c), or (d) of this section. ~~within 30 days and continue reevaluating the leak at least once every 30 days until there is a gas concentration reading of 0%. Leak repair must be complete within the repair deadline for a grade 3 leak under § 192.760(d)(2), or for a downgraded leak, the repair deadline under § 192.760(g)~~.[109]

(4) A post repair inspection is not required for any leak that is,

(i) eliminated by routine maintenance work—such as adjustment or lubrication of above-ground valves, or tightening of packing nuts on valves with seal;

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[105] *See* GPAC Voting Slide # 26 – Leak Grading and Repair. Grade 3 criteria and repair timelines. Bullet #1B.
"Repair timeline: HCA and Class 3+4 gas transmission lines: 1 year"

[106] This topic was not discussed during the GPAC meeting. Per the Association's August 2023 comments, the Associations recommend a 12-month reevaluation interval for Grade 3 leaks.

[107] The Associations recommend PHMSA refer to this process as a "re-check" as to not confuse it with leak investigation.

[108] *See* GPAC Voting Slide # 27 – Leak Grading and Repair (§ 192.760(e)).
"Recommend PHMSA consider the public safety and environmental implications of the following considerations based on the mandates from Congress, the GPAC discussion, state programs, other provisions of the NPRM and public comments: (vii) Applicability of post repair rechecks to all subsurface leaks on a gas distribution pipeline repaired, other than by the replacement or abandonment of the affected section of pipe, must be reevaluated after allowing the soil to vent and stabilize but not more than 30 calendar days after the repair, unless a zero percent reading was taken at the time the repair was complete."

[109] *See* PHMSA Presentation Slide #154 – Post Repair Inspection – § 192.760(e).
"PHMSA will provide clarification in the final rule concerning recheck requirements to address comments."

(ii) a grade 3 leak;
(iii) occurs on an ~~aboveground~~non-buried pipeline facility;
(iv) a result of an excavation damage;
(v) remediated through pipeline replacement; or
(vi) remediated through pipeline abandonment.[110]

(f) Upgrading Leak Grades. If at any time an operator receives information that a higher-priority grade condition exists in connection with a previously-graded leak, the operator must upgrade that leak to the higher-priority grade. When an operator upgrades a leak to a higher priority grade, the time period to complete the repair is the earlier of either the remaining time based on its original leak grade or the time allowed for repair under its new leak grade measured from the time the operator received the information that a higher-priority grade condition exists.

(g) Downgrading Leak Grades. A leak may not be downgraded to a lower-priority leak grade unless:
(1) a temporary repair to the pipeline has been made or a permanent repair was attempted but gas was detected during the post-repair **re-check** ~~**inspection**~~ under paragraph (e) of this section, **or**
(2) **The leak was initially graded inaccurately. Operators must address any additional necessary actions through Subpart N for individuals that inaccurately grade leaks**[111]

In **these** case**s**, the time period for repair is the remaining time allowed for repair under its new grade measured from the time the leak was **first** detected.

(h) Extension of Leak Repair. An operator may request an extension of the leak repair deadline requirements for an individual grade **2 or grade**[112] 3 leak with advance notification to and no objection from PHMSA pursuant to § 192.18. The operator's notification must show that the delayed repair timeline would not result in an increased risk to public safety, as well as that either the required repair deadline is impracticable, or that remediation within the specified timeframe would result in the release of more gas to the environment than would occur with continued monitoring. The notification must include the following:
(1) A description of the leaking facility including the location, material properties, the type of equipment that is leaking, and the operating pressure;
(2) A description of the leak and the leak environment, including gas concentration readings, leak rate if known, class location, nearby buildings, weather conditions, soil conditions, and other conditions that could affect gas migration, such as pavement;
(3) A description of the alternative repair schedule and a justification for the same; and
(4) Proposed emissions mitigation methods, monitoring, and repair schedule

(i) Recordkeeping.
(1) Records ~~**of the complete history of the investigation and grading of each leak must be retained for 5 years after the final post-repair**~~

[110] *See* GPAC Voting Slide # 27 – Leak Grading and Repair – § 192.760(e)).
"Recommend PHMSA consider … : (iv) exceptions for repairs for excavation damages; (v) exceptions for remediation of leak involving pipeline replacement (vi) exceptions for remediation where the leaking pipeline was abandoned."
[111] *See* PHMSA Presentation Slide #155 – Upgrading and Downgrading – §§ 192.760(f) and (g).
[112] *See* PHMSA Slide / Industry Comments

~~**inspection is completed under paragraph (e) of this section. These records include all records**~~ documenting **the** leak grading, **re-checks completed under paragraph (3) of this section,** ~~monitoring, inspections,~~ upgrades, and downgrades **must be retained for 5 years after final post-repair re-check.**

(2) Records of the ~~**detection, remediation, and repair of the leak must be retained for the life of the pipeline. This must include the**~~ date, location, and description of each leak detected, and **the date and** repair or remediation **method** ~~**of the same, made on the pipeline**~~ **must be retained for the life of the pipeline for gas transmission and gas distribution pipelines, unless a shorter timeline is prescribed by § 192.709**.[113]

(j) Leaks existing prior to the compliance date of this rule. Within 12 months of the compliance date, leaks other than hazardous leaks that are known to exist on or before the compliance date of the rule shall be:

(1) Repaired, or

(2) Re-evaluated and graded in accordance with this rule. Re-evaluated leaks shall be assigned a discovery date not later than the date the leak was first graded in accordance with this section.

IX. Reporting

A. Discussion

1) Gas releases should be exempt from flow-rate-based (e.g., 100 kg/hr) large-volume gas release reporting.

The GPAC's recommendation to align large-volume gas release reporting criteria with EPA reporting requirements stands to impose a flow-rate based reporting criterion of 100 kg/hr. While awareness of such high emission rates may be appropriate for some releases (e.g., leaks, where the release is relatively uncontrolled, and in which the time the release began may be unknown), imposing such a criterion on all releases would inadvertently require reporting of relatively small-volume, quickly-controlled releases.

Examples of such releases that are likely to be quickly controlled but may nevertheless involve an instantaneous flowrate in excess of 100 kg/hr include:

- Excavation damage involving a ½" puncture of a main operating at 20 psig
- Excavation damage involving a fully severed ½" service operating at 60 psig (no EFV assumed)
- Any wide-open 1" relief valve on a regulator station with 300 psig inlet pressure
- Any wide-open 2" relief valve on a regulator station with 60 psig inlet pressure

[113] *See* PHMSA Presentation Slide #158 – Recordkeeping – § 192.760(i)

- Proportional release from a relief valve on a commercial meter set
- Blowdown through a 2” blowoff of a launcher or receiver barrel that is operating at 1000 psig

PHMSA is also reminded that the reporting of emissions from such releases would be in scope for reporting, as per the proposed changes to Part F of Gas Distribution Annual Report, Part U of Gas Transmission & Gathering Annual Report, and Part E of LNG Annual Report. Because PHMSA will have visibility of these emissions through the annual reports, and given that such releases are objectively not large-volume, the 100 kg/hr criterion should be struck from the proposed large-volume gas reporting requirements.

2) Annual Report due date should be extended to June 15th

Industry requests that PHMSA adjust the natural gas distribution, transmission, gathering, and LNG annual reports be submitted on June 15th. This aligns with the much smaller Hazardous Liquids annual report submission date. This additional time will be needed to account for the recent addition for records evaluations and remediation, as well as the proposed requirements to evaluate the leak data and associated estimates. This extra time supports full and accurate completion of the annual report. As previously noted, § 192.703 was modified to remove overlapping reporting requirements to the EPA and PHMSA by removing the requirement to submit leak information for compressor stations that are required to comply with OOOO EPA requirements, which includes LNG facilities that are required to comply with local, state, and federal EPA reporting requirements.

3) PHMSA should simplify reporting requirements for instances of large-volume releases.

The Associations recommend that PHMSA revise the incident reporting criteria in § 191.3 to eliminate the unintentional 3 MMCF gas loss criterion, since such events can now be reported more appropriately through the large-volume gas release report. These incidents have long been understood to be emissions-driven rather than the type of pipeline safety-sensitive events which would typically require immediate notification to, and response of, emergency officials. Absorbing all volume-based gas reporting into the large-volume gas release reporting would allow incident reporting to be solely focused on safety-related events, allowing for more precise delineation between releases. Until such discernment is made in reporting, the likelihood is that large-volume release and incident reports will fail to accurately sort pipeline safety events from environmentally significant releases.

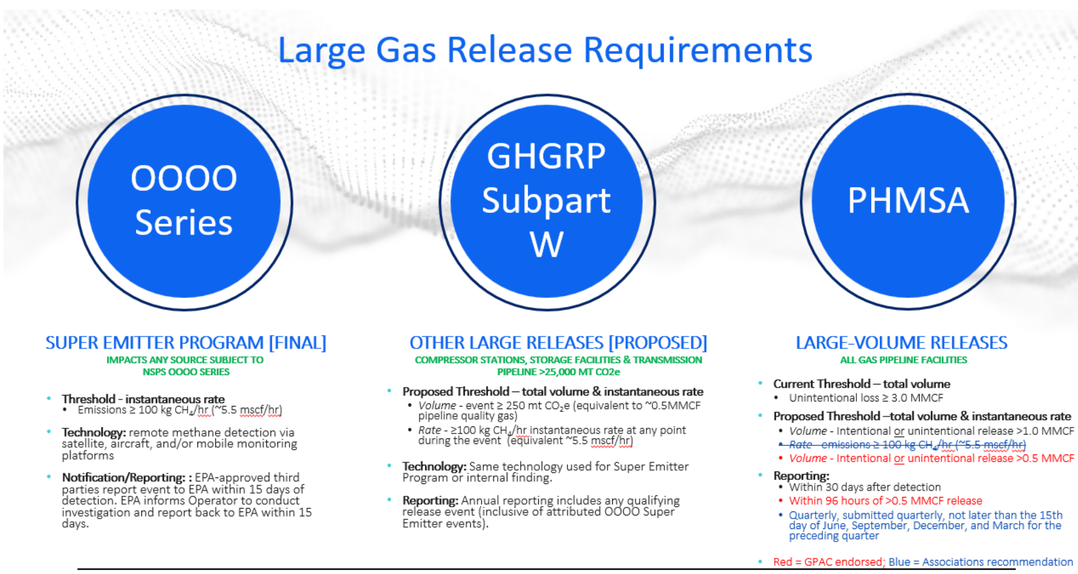
The Associations also ask PHMSA to clarify the jurisdictional delineation of reporting requirements proposed by PHMSA and EPA. The LDAR NPRM excluded certain requirements for patrolling, leak detection, and leak repair requirements for compressor stations that fall under EPA OOOO regulations. Industry recommends additional exclusions be listed under §§ 192.703 and 193.2624 to avoid unclear and potentially duplicative reporting requirements between PHMSA and EPA.

4) PHMSA should provide a structure for batch reporting of large-volume gas release reporting.

The Associations support GPAC's recommendation to move large-volume gas release reporting to a quarterly cadence. To better support this quarterly reporting, PHMSA should support a means of batch reporting of large-volume releases. In the absence of a batch reporting structure, operators will be forced to fill out individual reports for each large-volume gas release. This will not only be needlessly onerous from a reporting standpoint, but will also fail to realize the potential efficiencies that are made possible through quarterly reporting.

5) PHMSA should eliminate duplicative reporting requirements.

In § 192.703, PHMSA proposes exceptions for the EPA OOOO requirements applied to compressor stations. PHMSA should exclude any OOOO jurisdictional compressor station from methane emission and leak related reporting since this information will be collected and reported through EPA reporting requirements. Additionally, there are current and proposed reporting requirements under Subpart W that will also require additional reporting for compressor station related emissions and leaks. Operators should not be required to report the same data in different ways to different agencies. The chart below shows the overlapping reporting requirements and differences between relevant PHMSA and EPA regulatory regimes:



Source: INGAA

B. Updated regulatory text redline

§ 191.3 Definitions.
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Incident means any of the following events:

(1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility (UNGSF), liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:

(i) A death, or personal injury necessitating in-patient hospitalization;

(ii) Estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191.

~~**(iii) Unintentional estimated gas loss of three million cubic feet or more.**~~

(2) An event that results in an emergency shutdown of an LNG facility or a UNGSF. Activation of an emergency shutdown system for reasons other than an actual emergency within the facility does not constitute an incident.

(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.

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Large-volume gas release means an intentional or unintentional release of gas from a gas pipeline facility as that term is defined in § 192.3, **which is:**

- **500 thousand cubic feet or more of gas within 96 hours**~~**, or**~~
- ~~**100 kg/hr estimated flowrate on a gas transmission or gas gathering pipeline facility**~~

§ 191.17 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Annual report.

(a) Pipeline systems —

(1) Transmission, offshore gathering, or regulated onshore gathering. Each operator of a transmission, offshore gathering, or regulated onshore gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2-1. This report must be submitted each year, not later than ~~**March 15**~~, **June 15** for the preceding calendar year.

(2) Type R gathering. Beginning with an initial annual report submitted in March 2023 for the 2022 calendar year, each operator of a reporting-regulated gas gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2-3. This report must be submitted each year, not later than ~~**March 15**~~, **June 15**, for the preceding calendar year.

§ 191.19 Large-volume gas release report.

Each operator of a gas pipeline facility must report a large-volume gas release on DOT Form PHMSA–F7100.5. Each report must be submitted **quarterly, not later than the 15th day of June, September, December, and March for the preceding quarter of the calendar year** ~~**within 30 days after detection of a large-volume gas release**~~. **The first large-volume gas release report must be submitted for the quarter coinciding with a date 24 months from the effective date of rule.**

Prior to the compliance date of the rule, unintentional releases are exempt from large-volume gas release reporting. A large-volume gas release report is not required if an incident report has already been submitted under this part for the same event, **or a report for the same event has already been submitted, or will be submitted, to the U.S. Environmental Protection Agency acting pursuant to the authority provided in 42 U.S.C. 7401 et seq., a state, or local agency acting pursuant to a delegation of the authority provided in 42 U.S.C. 7401 et seq. by the U.S. Environmental Protection Agency** ~~**and the release volume identified in the incident report is within 10 percent of the total release volume on cessation of the release.**~~

§ 192.703 General.

* * * * *

(c) Leaks must be graded and repaired in accordance with the requirements in § 192.760.

(d) Compliance with **leak volumes and number of leaks reporting as part of §§ 191.17, 191.19**, 192.703(c), 192.705 for patrols, 192.706 for leakage surveys, 192.760(a)-(h) for leak grading and repair, 192.763 for advanced leak detection programs, and ~~**192.769**~~ **Subpart N** for qualification of leakage survey personnel, is not required for a compressor station on a gas transmission or gathering pipeline if:

(1) The facility is subject to methane emission monitoring and repair requirements under either:

(i) 40 CFR part 60, subparts OOOOa or OOOOb; or

(ii) an EPA-approved State plan or Federal plan which includes relevant standards at least as stringent as EPA's finalized emissions guidelines in 40 CFR part 60, subpart OOOOc;

§ 192.18 How to notify PHMSA.

* * * * *

(d) An operator shall submit a notification when it cannot meet the required remediation time frame per § 192.760(h).

X. LNG Facilities

A. Discussion

1) As with the Transmission Pipeline Blowdown Mitigation provisions, PHMSA must clarify that operators are required to reduce, not minimize, emissions using the methods specified in § 193.2523.

The Associations propose modifying the regulatory text language from *eliminating* to *reducing* in §§ 193.2503, 193.2605, and 193.2523 to reflect similar considerations in the transmission pipeline blowdown mitigation provisions proposed in § 192.770.

The Committee also proposed to modify the emission reduction methods proposed in the NPRM because they were not applicable to LNG facilities and management of cryogenic fluid. In addition, the limited space within LNG facilities will not support the use of a temporary flare due to thermal impacts and for safety. Other methane emission reduction options include transferring gas upstream of liquefaction or transferring LNG to trucks where a loading facility is on site and the reduction in pressure can be managed safely to ensure that facility and component MAOPs are not exceeded or an existing storage tank or [local] pressure vessel, designed to contain LNG. Many LNG facilities are constructed to route methane emissions to the facility's flare during planned work on vessels and cryogenic lines. In addition, many relief valves at facilities are designed to relieve into process piping rather than to the atmosphere. LNG facilities are rarely taken out of service but if an emergency arises, the facility may vent methane to the atmosphere to bring it to a safe state. Industry recommends that PHMSA study this issue and provide more methane reduction strategies through its LNG Center of Excellence. The LNG Center of Excellence, as a part of its chartered mission, should work with stakeholders including existing facilities to determine best practices and document additional safe methods for reducing methane emissions during planned maintenance.

The Associations support the Committee recommendation to align LNG leak detection technology sensitivities to those proposed for transmission pipelines and EPA OOOO requirements while providing for the unique designs of facilities that are not normally accessible to personnel. GPAC recommended a grading and repair requirement for LNG facilities that would be similar to the proposed § 192.760 for LNG facilities. The Associations support a tailored leak grading and repair requirement for LNG facilities as stipulated in the proposed regulatory text below.

There are many LNG facilities in operation today that follow state and federal EPA requirements. The facilities that meet current EPA requirements or will be required to meet future EPA requirements should become EPA jurisdictional at the time they are required to meet local, state, or federal EPA requirements. This would align with the proposed § 192.703 exclusion of compressor stations that will be required to comply with EPA OOOO regulations.

Finally, the Associations propose to modify the regulatory language on leak survey frequency to align with public suggestion and the ensuing Committee recommendation to use the proposed transmission line leak survey frequencies as a model for the LNG facility frequency, given that the Committee recommendation was to use this model for small-scale facilities. It is suggested that a reasonable differentiation between large-scale and small-scale facilities is whether or not an LNG site is a maritime facility. Such import/export facilities are much larger and in continuous operation as compared to most peak-shaving facilities. The Associations remind PHMSA that a thorough review of proposed changes should be conducted by the LNG Center of Excellence in partnership with industry stakeholders.

B. Updated regulatory text redline

§ 193.2503 Operating procedures.

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(h) ~~Eliminating~~ **Reducing** leaks and ~~minimizing~~ releases of gas.

§ 193.2605 Maintenance procedures.

****

(b)

***

(3) Procedures for ~~eliminating~~ **reducing** leaks and ~~minimizing~~ releases of gas

§ 193.2523 Reducing ~~Minimizing~~ emissions from blowdowns and boiloff.

(a) Except as provided in paragraph (b) of this section, an operator of an LNG facility must **reduce** ~~minimize~~ intentional emissions of natural gas from LNG facilities that would exceed ~~1.0~~ **500** MCF **or more of gas within 96-hour period** without mitigative action, including tank boiloff or blowdowns for repairs, construction, operations, or maintenance. The operator must **reduce** ~~minimize~~ the release of natural gas to the environment by use of one or more of the following methods, **where possible**:

(1) Isolating a smaller section of the piping segments by use of valves ~~or the installation of control fittings~~;

(2) Routing gas released ~~from the facility~~ to ~~a~~ **the facility's** flare, or to other equipment for use as fuel gas;

~~(3) Transferring gas or LNG to a storage tank or local pressure vessel; or~~

~~(4) Employing an alternative method demonstrated to result in release volume reductions of at least 50% compared to venting gas directly to the atmosphere without mitigative action.~~

(b) An operator is not required to comply with the provisions of paragraph (a) of this section during an emergency resulting in the activation of their emergency procedures under § 193.2509. ~~An operator must document each emergency release without mitigation described in paragraph (b) of this section, including the justification for release without mitigation.~~

(c) The operator must document the method or methods used and describe how those methods **reduce** ~~minimize~~ the release of natural gas to the environment.

§ 193.2624 Leakage surveys.

(a) ~~Each~~ operator ~~of an LNG facility, including mobile, temporary, and satellite facilities~~ must conduct periodic ~~methane~~ leakage surveys, ~~on equipment and of designated~~ components ~~within their facilities~~ containing natural gas, methane or LNG, at the following intervals, unless monitored by continuous gas monitoring.

(i.) LNG facilities with maritime capabilities and any other LNG facility in class 4 location shall be surveyed at least four times each calendar year, with a maximum interval between surveys not exceeding 4 ½ months, using leak detection equipment.

(ii.) All other LNG facilities shall be surveyed at least twice a year with intervals not exceeding 7 ½ months.

(b) Acceptable leak detection equipment includes Optical Gas Imaging, ~~must be~~ or equipment capable of a sensitivity ~~detecting and locating all methane leaks producing a reading~~ of 10 kg/hr at 90% probability of detection, 5 parts per million, 5 parts per million-meter, 1% LEL, or 500 parts per million for continuous gas monitoring equipment ~~more of within 5 feet of the component or equipment surveyed~~.

(c) Operators must have written procedures providing for each of the following:

(1) Calibrate ~~Validating~~ the leakage survey equipment and performin~~ing~~ leakage surveys consistent with the equipment manufacturer's instructions for survey methods and allowable environmental and operational parameters; Leak detection equipment must be recalibrated or replaced following any indication of malfunction

~~(2) Validating the sensitivity of this equipment by the operator before initial use by~~
~~testing with a known concentration of gas at a required offset condition of 5 feet; and~~

(3) ~~Calibrating the equipment consistent with the equipment manufacturer's instructions for calibration and maintenance. Leak detection equipment must be recalibrated or replaced following any indication of malfunction~~. Designate and document the components not subject to the periodic leakage survey requirements, including any components that are inaccessible, unsafe to monitor, or difficult to monitor during one or more survey intervals

(~~c~~d) Each operator must maintain records of the leak survey and equipment sensitivity ~~validation~~ and calibration for five years after the leakage survey.

(e) General. Each operator must have and follow written procedures for grading and repairing or remediating leaks that meet or exceed the requirements of this section.

(1) These requirements are applicable to leaks found on all portions of a LNG facility piping including, but not limited to, pipe, valves, flanges, meters, regulators, tie-ins.

(2) The leak grading and repair procedure methods must prioritize leak repairs/remediation by the hazard to public safety and the environmental significance environment.

(3) Each leak must be investigated and a leak grade established as part of the leak investigation process. immediately and continuously until a leak grade determination has been made.

(f) Grade 1 leaks.

(1) A grade 1 leak is a leak with any of the following characteristics:

(i) Any leak that, in the judgment of operating personnel is regarded as an existing or probable hazard to public safety;

(ii) Any amount of escaping gas through a leak that has ignited;

(iv) A leak that has a leak rate equal to or greater than 100 kg/hr

(v) Any reading of 80% or greater of the LEL in a confined space an enclosure;

(viii) Any leak defined as an incident in § 191.3.

(2) An operator must promptly repair a grade 1 leak and eliminate the hazardous conditions by taking immediate and continuous action by operator personnel at the scene. Immediate action means the operator will begin instant efforts to remediate and repair the leak upon detection and to eliminate any hazardous conditions caused by the leak. Continuous means that the operator must maintain on-site remediation efforts until the leak repair has been completed. This may require one or more of, but not limited to, the following actions be taken without delay:

(i) Implementing an emergency plan pursuant to § 193.2509;
(ii) Evacuating premises;
(iii) Blocking off the area;
(iv) Rerouting traffic;
(v) Eliminating sources of ignition;
(vii) Stopping the flow of gas by closing valves or other means; or
(viii) Notifying emergency responders.

(g) Grade 2 leaks.

(1) A grade 2 ~~leak constitutes a probable future hazard to persons or property or a significant hazard to the environment, and~~ includes any leak (other than a grade 1 leak) with any of the following characteristics:

(i) A reading between 20% and 80% of the LEL in a confined space;

(ii) Any reading of gas that does not qualify as a grade 1 leak that occurs in the body of a pipeline line operating at a stress greater than 30% SMYS or a pipe leak measured to be greater than 10 kg/hr; or

(iii) Any leak that, in the judgment of operating personnel, is of sufficient magnitude to justify scheduled repair within 12 months or less.

(2) An operator must schedule repair based on the severity or likelihood of hazard to persons, property, or the environment. A grade 2 leak must be repaired/remediated within 12 months of detection except as described below, or unless a shorter repair deadline is required by the operator's procedures. The operator must reevaluate each grade 2 leak at least once every 6 months until it is repaired.

(h) An operator must complete repair of known grade 2 leaks existing on or before [effective date of the final rule] before [date 1 year after the effective publication date of the final rule] unless an extension request has been approved

(i) Grade 3 leaks.

(1) A grade 3 leak is any leak that does not meet the criteria of a grade 1 or grade 2 leak. In order to qualify as a grade 3 leak, none of the criteria for grade 1 or 2 leaks can be present.
(2) A grade 3 leak must be repaired within 36 months of detection, except as described below: (i) A grade 3 leak known to exist on or before [effective date of the final rule] must be repaired prior to [date 3 years after the effective publication date of the final rule] unless an extension request has been approved under (h).
(3) Each operator must reevaluate each grade 3 leak at least once every 12 months until repair/remediation of the leak is complete.

(i) Post-repair re-check

(1) An operator must conduct a post-repair leak re-check no later than 30 days after the repair, if 0% gas concentration readings cannot be achieved after repair due to residual gas in the soil.

(2) If a post-repair re-check shows a gas concentration reading greater than 0%, operator must take the following actions:

(i) If the re-check shows a gas concentration lower than the most recent read, the operator must perform a re-check within 30 days and continue re-checking at least once every 30 days until there is a gas concentration reading of 0%.

(ii) If the re-check shows a gas concentration higher than (or equal to) the most recent read, the operator must investigate and repair or grade the leak according to paragraph § 193.2624(g), § 193.2624(h), or § 193.2624(i).

(3) A post repair re-check is not required for:

(i) any leak that is eliminated by routine maintenance work—such as adjustment or lubrication of aboveground valves, or tightening of packing nuts on valves with seal leaks; and is
(ii) a grade 3 leak or one that occurs on a non-buried pipeline facility.;
(iii) repairs for excavation damages;
(iv) remediation of leak involving pipeline replacement; or
(v) remediation where the leaking pipeline was abandoned.
(k) Upgrading leak grades.

If at any time an operator receives information that a higher-priority grade condition exists in connection with a previously graded leak, the operator must upgrade that leak to the higher-priority grade. When an operator upgrades a leak to a higher-priority grade, the time period to complete the repair is the earlier of either the remaining time based on its original leak grade or the time allowed for repair under its new leak grade measured from the time the operator received the information that a higher priority grade condition exists.

(j) Downgrading leak grades.

A leak may not be downgraded to a lower priority leak grade unless:

(i) A temporary repair to the pipe has been made or a permanent repair was attempted but gas was detected during the post-repair re-check inspection under paragraph (e) of this section, or

(ii) The leak was initially graded incorrectly. Operators must address any additional necessary actions through training for individuals that incorrectly grade leaks. In these cases, the time period for repair is the remaining time allowed for repair under its new grade measured from the time the leak was first detected.

(k) Extension of leak repair/remediation.

An operator may request an extension of the leak repair deadline requirements for an individual grade 2 leak or grade 3 leak with advance notification to and no objection from PHMSA pursuant to § 192.18. The operator's notification must show that the delayed repair timeline would not result in an increased risk to public safety, as well as that either the required repair deadline is impracticable, that remediation within the specified time frame would result in the release of more gas to the environment than would occur with continued monitoring, or that a replacement project is pending and would negate

the need to make any repair. The notification must include the following:

(1) A description of the leaking facility including the location, material properties, the type of equipment that is leaking, and the operating pressure;

(2) A description of the leak and the leak environment, including gas concentration readings, leak rate if known, class location, nearby buildings, weather conditions, soil conditions, and other conditions that could affect gas migration, such as pavement;

(3) A description of the alternative Repair/remediation schedule and a justification for the same; and

(4) Proposed emissions mitigation methods, monitoring, and repair schedule.

(l) Recordkeeping.

(1) documenting the leak grading, re-checks completed under paragraph (j) of this section, upgrades, and downgrades must be retained for 5 years after final post-repair re-check.

(2) Records of the date, location, and description of each leak detected, and the date and repair or remediation method applied must be retained for the life of the pipeline.

XI. Hydrogen

A. Discussion

1) PHMSA should make it clear that the proposed LDAR rules apply – without distinction – to hydrogen-blended natural gas pipelines.

As previously argued by the Associations, the available literature does not support restricting the leak grading options for natural gas-hydrogen blends[114]. PHMSA helped clarify the intended scope of the proposed restrictions (namely, § 192.760(c)(viii)) at the GPAC Meeting, to apply only to leaks from pure hydrogen pipelines.[115]

[114] Comments On Pipeline Safety: Gas Pipeline Leak Detection and Repair; Filed by American Gas Association, American Petroleum Institute, American Fuel & Petrochemical Manufacturers, American Public Gas Association, GPA Midstream Association, Interstate Natural Gas Association of America, and Northeast Gas Association; August 16, 2023 (Docket No. PHMSA-2021-0039), pg. 65-66.
[115] *See* GPAC Transcript March 26, 2024.
Page 23.

The Associations support the Committee's recommendation to apply the NPRM as it relates to natural gas pipelines to any pipeline with natural gas-hydrogen blends (predominately natural gas).[116] Since there are no extant natural gas-hydrogen blending projects that are not predominantly natural gas in the United States, there are no provisions within the NPRM that should be distinct to pipelines with natural gas-hydrogen blends.

As written, § 192.760(c)(viii) may be interpreted to apply to any leakage of a molecule of hydrogen gas. PHMSA must make it clear that there are no such leak grading restrictions being placed on hydrogen blends in this rulemaking. Furthermore, as the Associations have stated previously,[117] there is nothing precluding LP gas leaks from meeting Grade 3 criteria in the GPTC guidance or any other existing literature. PHMSA's proposal to forbid LP gas leaks from being graded as Grade 3 (if they do not otherwise meet Grade 1 or Grade 2 criteria) is not supported and should be removed from any final rulemaking.

2) Distinct LDAR provisions for dedicated hydrogen pipelines should not appear in the final rule.

There are approximately 1,500 miles of dedicated hydrogen pipelines in the United States today. These pipelines are subject to current regulations under 49 CFR 192, including current requirements for leak surveys.

Notwithstanding 49 CFR 192's regulation of these hydrogen pipelines, the specific methane detection technology considerations proposed by PHMSA in this NPRM and voted upon by GPAC are not appropriate for dedicated hydrogen pipelines. Consequently, the GPAC declined to recommend that PHMSA consider LDAR alternatives for dedicated hydrogen pipelines (e.g., applying an alternative ALDP performance standard) as part of this rulemaking. Accordingly, the Associations maintain that § 192.760(c)(viii) is out of place in a rulemaking focused on methane leaks, and including it in a final rule is inappropriate at this time.

PHMSA should consider how best to exempt hydrogen-dedicated pipelines from rules written to explicitly regulate methane detection and emissions mitigation, including (but not limited to) §§ 192.760, 192.763, and 192.770.

Mr. Zamarin: "The proposed rule does put some restrictions on blended hydrogen, right? Like, you can't have, like, a grade 3 leak with blended hydrogen; is that correct?"

Mr. Palabrica: "So the -- the grade 2 criteria that you're referring to in the proposal is admittedly ambiguous. I think that the intent was for that to -- for gaseous hydrogen to refer to pure hydrogen pipelines."

[116] *See* GPAC Voting Slide 34 – Hydrogen

Slide # 34, Bullet #1.

"For natural gas-hydrogen blends (predominately natural gas): apply the NPRM as it applies to natural gas pipelines."

[117] Comments On Pipeline Safety: Gas Pipeline Leak Detection and Repair; Filed by American Gas Association, American Petroleum Institute, American Fuel & Petrochemical Manufacturers, American Public Gas Association, GPA Midstream Association, Interstate Natural Gas Association of America, and Northeast Gas Association; August 16, 2023 (Docket No. PHMSA-2021-0039), pg. 66.

B. Updated regulatory text redline

§ 192.760 Leak grading and repair.

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(c) Grade 2 leaks.

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(viii) ~~**Any leak of LPG or hydrogen gas that does not qualify as a grade 1 leak; or**~~

XII. Compliance Deadlines

A. Discussion

1) Leaks that are known by the operator to exist before the compliance date of this rule must not be retroactively assigned a repair (or re-evaluation) date based on the new leak grading and repair regime introduced by § 192.760.

The GPAC proposed a compliance date of 36 months from the publication of the final rule, with compliance timelines beginning on the nearest January 1 (effectively, 30-42 months). Pursuant to this compliance timeline, the GPAC declined to make a specific recommendation on how to assign re-evaluation and repair schedules to leaks that are known to exist by the operator prior to the compliance date.

There are three critical factors that PHMSA must consider in dealing with these leaks:

- Leak grading regimes in place prior to the compliance date of the rule are either aligned with existing state regulations, or have been implemented entirely voluntarily by operators. Until the requirements of § 192.760 are imposed, there will be considerable variability in how operators assign leak grades, as well as the associated timelines for re-evaluation and repair of these leaks. Therefore, PHMSA cannot establish timelines for re-evaluating and repairing existing pre-rule Grade 2 leaks, since an operator's pre-rule "Grade 2" criteria may have little relation to PHMSA's definition in § 192.760, and since some operators may not even utilize "Grade 2" within their pre-rule leak grading regimes.
- If PHMSA attempts to retroactively impose new requirements onto known leaks on an operator's system, the dates of discovery of those leaks may not be transferable. For example, if a leak graded or repaired under the new leak grading regime established by § 192.760, the date the leak was first discovered (under the old leak grading regime) might automatically show the operator to be out of compliance with the repair schedules defined in § 192.760.

- Leaks repaired or otherwise eliminated prior to the compliance date should not be subject to this rulemaking.

Therefore, PHMSA should adopt language in the final rule specifying that within 12 months of the compliance date, leaks (other than hazardous leaks) that are known by the operator to exist on or before the compliance date should be:

- Repaired in accordance with the operator's pre-rule grading and repair procedures, or
- Re-evaluated and graded in accordance with § 192.760, with the discovery date of re-evaluated leaks set not later than the date the leak was first graded in accordance with § 192.760.

Importantly, this approach for transitioning from the pre-rule (operator-defined) leak grading regime would avail operators of the exceptions to the leak repair schedules defined in § 192.760 (e.g., leaks to be eliminated through planned pipe replacement projects, as well as low-emitting Grade 3 leaks).

2) **PHMSA should limit any 18-month "program development" stage-gate (as recommended by the GPAC) to ALDP requirements, and must ensure that any requirement for an interim plan does not require procedures to be written into operators' O&M manual.**

The GPAC recommended that PHMSA require operators to "develop the program" within 18 months of the final rule effective date. PHMSA should make it clear that this 18-month program development stage gate be limited to the ALDP program described by § 192.763. Focusing the program development on ALDP requirements is prudent for three reasons. First, the Committee recommended development of "the program," and among all other LDAR provisions, only ALDP is programmatic.

Second, for most operators the other LDAR provisions (leakage survey, patrol, leak grading and repair, etc.) are almost certain to be more mature in terms of written plans, technologies, and training of personnel than is the case for ALDP. On the whole, a shorter runway will be required for developing written plans and practices for complying with these sections of the LDAR rule.

Finally, in recommending the 18-month plan development milestone, the Committee clearly sought to apply the precedent of integrity management to the LDAR program development.[118] However, integrity management rules were

[118] *See* GPAC Transcript March 27, 2024.

Pages 35-36.

Mr. Zamarin: "That was the intent of our second bullet that says, develop the program within 18 months of the effective date. That's consistent with the concept of how we did integrity management that you had to have policies and procedures and a program in place that could be audited and verified by PHMSA so it was demonstrated that you had reached that interim milestone as you were building up towards implementation of the activities….The typical construct -- and I do think we should recognize and, frankly, work within the construct -- the typical construct would be that we develop those programs and they're subject to audit and PHMSA comes out and audits the availability of those, the compliance of those. I mean, that's typically how introduced in Subparts O and P of 49 CFR 192. Given that much of the proposed LDAR rule resides in Subparts L and M, the Associations are concerned that any requirement to have written LDAR plans in place will necessarily require operators to publish these written plans within their manual for operations and maintenance, as well as keep records necessary for administering these procedures (as per §§ 192.603(b) and 192.605(a)). PHMSA must take care to consider this when adapting a precedent from Subparts O and P.

3) Any 18-month "program development" stage-gate requirements should recognize operators' ongoing efforts to eliminate leaks and reduce emissions, and should not create difficulty or uncertainty for operators as they prepare to comply with the LDAR final rule.

The more concerning impediment to timely LDAR program development is not the 30–42-month compliance timeline recommended by the GPAC, but rather creating unnecessary uncertainty for operators while they develop their programs. Operators need assurance that development of a written LDAR program will not be disrupted by an 18-month stage-gate requirement, the accompanying scrutiny by state or federal pipeline safety inspectors, and the prospect of being asked to change course with perhaps less than 12 months remaining before the compliance date.

Aligned with the Committee's recommendation is the natural course of implementation that the industry will pursue when looking to comply with the new requirements. As soon as the Final Rule is published, operators will begin transitioning through the purchase of new equipment (if necessary), training and qualification of individuals, pursuing contracts with contract leak survey providers, modification of their procedures and standards, and transitioning their leak survey cycles to align with the new requirements. The Committee expressed some concern that operators will wait up to 36 months to begin implementation of the requirements of this rule. This approach is not feasible for any operator that is not already nearly prepared to comply with the LDAR provisions, as is evident by the Associations' insistence that a full 36 months is necessary to prepare to comply with this rulemaking.

The Associations recommend that the 18-month plan development be limited to three elements:

(i) A process for the selection of leak detection equipment
(ii) Identified leak detection equipment and their application
(iii) Leak survey and pinpointing practices

The Associations believe it is critical to allow no less than 18 months to develop a plan with these elements, specifically as it relates to commercial readiness, vendor availability, compliance with leak survey frequencies, execution of field pilots, and the costs of leak detection technology in the transmission and

that happens. I don't know if PHMSA wants to speak to that process, but that -- I -- from what I recall, that's how we did integrity management and there were onsite audits of all those policies and procedures, many of which required today access to electronic systems in which we have records and we have the systems that drive the work that we do."

gathering sectors. As operators evaluate requirements for ALDP plan development, including ability to meet instrument sensitivity criterion (e.g., 10 kg/hr sensitivity at 90% Probability of Detection for transmission leak surveys), evaluating methods of estimating emissions for annual reporting, it is likely they will compete across asset types (e.g., transmission versus gathering) for vendor resources. To give one example of the need for additional time for technology maturation, the Methane Emissions Technology Evaluation Center (METEC)[119] currently identifies just 3 of 5 manned aerial leak detection technology vendors that have documented test plans demonstrating adherence to the technology requirements proposed by PHMSA. On April 3, 2024, INGAA submitted a white paper entitled, "Lack of certainty in quantification of methane emissions from remote sensing technologies" to Docket ID Number EPA-HQ-OAR-2023-0234, in response to the Subpart W requirements and Method 21 Alternative Monitoring Requirements outlined in the OOOOa - OOOOc rules. In these programs, EPA allows operators to use alternative technology at established screening thresholds at defined leak survey frequencies. This white paper summarizes nine recent studies where mobile to aerial technologies are deployed and discrepancies are noted. As operators prepare to comply with the rule, establishing uniform consensus standards and intensive benchmarking will be imperative to avoid over-reporting.

Finally, PHMSA is reminded that the self-executing provisions of Section 114 of the PIPES Act of 2020, as well as PHMSA's oversight of their implementation, have ensured that operators are repairing hazardous leaks, minimizing releases from pipeline facilities, and eliminating leaks through identification and remediation of leak-prone pipe. These activities have driven operators to reduce leaks and vented emissions far more effectively and demonstrably than could any proposal to mandate LDAR programs be developed (but not followed) within 18 months of the final rule's effective date. In summary, the need for operators to "get started" is already acknowledged and enforced through Section 114 of the PIPES Act 2020.

B. Updated regulatory text redline

The Associations support the GPAC's recommendation to establish a compliance date not less than 30 months from the date the final rule is published, to begin on January 1.

§ 192.763 Advanced Leak Detection Program.

*****

(d) *General*

(1) Advanced Leak Detection Program (ALDP) Elements. Each operator must have and follow a written ALDP that implements the requirements of this section no later than [INSERT DATE = NEAREST JAN 1, AFTER PUBLICATION DATE + 36 MONTHS]:

(2) No later than [Effective date of the rule + 18 MONTHS] an operator of a covered pipeline segment must develop a written initial Advanced Leak Detection Program (ALDP)

[119] Methane Emissions Technology Evaluation Center (METEC). https://metec.colostate.edu/

framework. The initial ALDP framework must consist, at a minimum, of the following:

(i) A process for the selection of leak detection equipment

(ii) Identified leak detection equipment and their application

(iii) Leak survey and pinpointing practices to be implemented through procedures on [INSERT DATE = NEAREST JAN 1, AFTER PUBLICATION DATE + 36 MONTHS].

PHMSA should address issues surrounding leaks that are known by the operator to exist on before the compliance date of the rule by revising § 192.760 as follows:

§ 192.760 Leak grading and repair.

(j) Leaks existing prior to the compliance date of this rule. Within 12 months of the compliance date, leaks other than hazardous leaks that are known to exist on or before the compliance date of the rule shall be:

(1) Repaired, or

(2) Re-evaluated and graded in accordance with this rule. Re-evaluated leaks shall be assigned a discovery date not later than the date the leak was first graded in accordance with this section.

XIII. Operator Qualifications

A. Discussion

1) The most appropriate place for codifying requirements for qualification of individuals performing leakage survey, investigation, grading, and repair is in Subpart N.

The Associations previously provided comprehensive comments as to why the introduction of § 192.769 is redundant and could cause considerable regulatory confusion.[120]

In response, PHMSA stated during the GPAC meeting that they did not intend to "eliminate an operator's ability to perform tasks using subpart N which includes span of control," or "require individuals be trained in tasks they are not responsible for."[121] The Associations support this stance and reaffirm that in the absence of other distinctions which have made separate qualification requirements necessary for certain activities (e.g., welding, plastic fusion, and tapping), the most appropriate path to providing clarity in the final rule is to strike the proposed § 192.769 altogether.

[120] Comments On Pipeline Safety: Gas Pipeline Leak Detection and Repair; Filed by American Gas Association, American Petroleum Institute, American Fuel & Petrochemical Manufacturers, American Public Gas Association, GPA Midstream Association, Interstate Natural Gas Association of America, and Northeast Gas Association; August 16, 2023 (Docket No. PHMSA-2021-0039), pgs. 127-128.

[121] *See* GPAC Slide # 87 – Operator Qualifications - § 192.769. Bullets #2 and #3.

B. Updated regulatory text redline

The Associations recommend the proposed addition of § 192.769 be removed.

~~**§ 192.769 Qualification of leakage survey, investigation, grading, and repair personnel.**~~

~~Only individuals qualified under subpart N of this part may conduct leakage survey, investigation, grading, and repair. Individuals qualified under subpart N must also possess training, experience, and knowledge in the field of leakage survey, leak investigation, and leak grading, including documented work history or training associated with those activities.~~

XIV. Investigation of Failures

A. Discussion

1) Pipeline "failure" should remain tied to the functional definition developed under ASME/ANSI B31.8S, with important qualifiers.

The Associations reiterate that individual leaks "generally do not render a pipeline (in whole or in part) either 'completely inoperable,' 'incapable of satisfactorily performing its intended function,' or 'unreliable or unsafe for continued use'"[122], the criteria historically understood to describe a failure under ASME/ANSI B31.8S. Expanding this criteria to include all leaks would be impracticable, would swamp resources used in pipeline failure investigations (i.e., laboratories), and would unquestionably diminish the effectiveness of investigating failures considered significant by the operator.

The Associations support the GPAC's recognition of the importance of making a clear distinction between failures and (most) leaks.[123] PHMSA is reminded, however, that the definition of failure should be tied to an *event*, so as not to associate the intended end of a pipeline's life (e.g. for capacity or reliability reasons) with "failure."

B. Updated regulatory text redline

The Associations recommend the language in § 192.617 to be revised as follows:

[122] Comments On Pipeline Safety: Gas Pipeline Leak Detection and Repair; Filed by American Gas Association, American Petroleum Institute, American Fuel & Petrochemical Manufacturers, American Public Gas Association, GPA Midstream Association, Interstate Natural Gas Association of America, and Northeast Gas Association; August 16, 2023 (Docket No. PHMSA-2021-0039), pgs. 121.

[123] *See* GPAC Transcript March 27, 2024.

Page 150. Ms. Gosman "I think I think we're interested in making sure that we get as much information as possible out of bigger events that we can then use to make sure these don't happen again, right? And, from that perspective, I think that PHMSA can work on the language to ensure that that's the goal."

§ 192.617 Investigation of failures and incidents

………

(e) Failure defined. For the purposes of this section, the term failure means ~~when~~ an event in which any portion of a pipeline becomes completely inoperable, is incapable of ~~safely~~ satisfactorily performing its intended function, or has become unreliable or unsafe for continued use.

XV. Definitions

A. Discussion

1) Proposed Definitions Supported by Associations

As provided in the Associations comments in response to the NPRM, the Associations support PHMSA's proposed definitions for the following terms:

- *Substructure*
- *Tunnel*
- *Wall-to-Wall paved area*

2) Association Supported Definitions with Recommended Edits

While not discussed during the GPAC meeting, but highlighted during the public comments, the Associations encourage PHMSA to modify their proposals to the following definitions to avoid conflict with definitions from other federal agencies or to align with commonly understood definitions for the same terms.

- *Enclosure*
- *Gas-associated substructure*
- *Lower explosive Limit (LEL)*

The Associations proposed edits to these definitions are provided in the subsequent section of these comments.

3) "Business District" should not be defined through this rulemaking.

Although a definition of business district was not proposed by PHMSA in the NPRM, PHMSA has invited discussion on whether a definition should be included in a final rule.

The Associations highlight that many state regulators have already developed state specific definitions of a business district, each developed with that state's unique territory in mind. For example, dense urban environments leverage population density as a factor for a risk prioritization methodology. A one-size-fits all definition of a business district is inappropriate in light of the significant geographical and operational differences that exist throughout the United States.

The original authors of the term, the Gas Pipeline Technology Committee (GPTC), developed the concept of a *Business District*[124] because of the need to call attention to structures that may contain people who are not aware that the building is being served by natural gas. In contrast, homeowners, residents, and business owners are aware of the utility services provided to that building and therefore are theoretically more attuned (e.g., through public awareness efforts) to pipeline safety considerations. GPTC encouraged natural gas distribution operators to perform annual leak survey in "business districts," in part to acknowledge portions of their pipeline system where non-customers are more likely to be in proximity.

In short, a fit-for-purpose definition of "business district," based on state-by-state or operator-by-operator considerations, is appropriate. The Associations oppose defining this term within 49 CFR Part 192.

4) Definitions not necessary for this rulemaking

The Associations do not believe it is necessary for PHMSA to codify a definition for *leak* or *hazardous leak*. The term does not appear anywhere in the proposed regulatory text, and therefore a definition is not necessary, and would only cause confusion for the regulated community.

B. Updated regulatory text redline

§ 192.3 - Definitions

~~**Confined space**~~ ***Enclosure*** means any subsurface structure, other than a building, of sufficient size to accommodate a person, and in which gas could accumulate or migrate. These include vaults, certain tunnels, catch basins, and manholes.

Gas-associated substructure means a substructure that is part of an operator's pipeline **delivery infrastructure,** but that is not **itself** designed to contain **or transport** gas.

Lower explosive Limit (LEL) means the minimum concentration of gas or vapor in air below which propagation of a flame does not occur in the presence of an ignition source **at ambient pressure and temperature.**

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[124] GPTC Guide for Gas Transmission, Distribution, and Gathering Piping Systems: 2022 Edition. Guide Material for § 192.723 – Distribution Systems: Leakage surveys.

In determining business districts, the following should be considered.

(a) Areas where the public regularly congregates or where the majority of the buildings on either side of the street are regularly utilized for industrial, commercial, financial, educational, religious, health, or recreational purposes.

(b) Areas where gas and other underground facilities are congested under continuous street and sidewalk paving that extends to the building walls on one or both sides of the street.

(c) Any other area that, in the judgment of the operator, should be so designated.

XVI. Uprating

A. Discussion

As the Associations stated previously, it is critical that PHMSA retain the current requirements for uprating specified in §§ 192.553 and 192.557. PHMSA should"

> *"…[allow] operators to grade, monitor, and repair leaks in accordance with proposed § 192.760 while proceeding with uprating procedures. A blanket requirement to repair any leak, even those identified by Congress as so small that they would not create a potential hazard, is unreasonable and lacks technical support. This position diverts from GPTC guidance that has long recognized a detectable leakage rate criteria during pressure testing."* [125]

PHMSA's proposal to synonymize "leak" and "hazardous leak" in the NPRM is inappropriate, as is the companion changes to §§ 192.553 and 192.557 that would require *any* leak to be repaired during uprating.

B. Updated regulatory text redline

§ 192.553 General requirements.

(a) Pressure increases. Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:

(1) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.

(2) Each leak detected must be repaired before a further pressure increase is made, **except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous**~~.~~

….

§ 192.557 Uprating: Steel pipelines to a pressure that will produce a hoop stress less than 30 percent of SMYS: plastic, cast iron, and ductile iron pipelines.

(a) Unless the requirements of this section have been met, no person may subject:

[125] Comments On Pipeline Safety: Gas Pipeline Leak Detection and Repair; Filed by American Gas Association, American Petroleum Institute, American Fuel & Petrochemical Manufacturers, American Public Gas Association, GPA Midstream Association, Interstate Natural Gas Association of America, and Northeast Gas Association; August 16, 2023 (Docket No. PHMSA-2021-0039), pgs. 58-59.

(1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or
(2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

(1) Review the design, operating, and maintenance history of the segment of pipeline;
(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, **except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.**

XVII. Conclusion

The Associations commend PHMSA's continuing commitment to pipeline safety and appreciates the opportunity to comment on the proceedings of the GPAC Meeting. The Associations remain committed to working with PHMSA to address our concerns with the proposed requirements, to meet the Congressional mandates, and continue to enhance pipeline safety. We look forward to continuing our engagement in the GPAC process and providing industry's insights, experience, and recommendations as the process moves forward.

Respectfully submitted,
Date: April 29, 2024

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

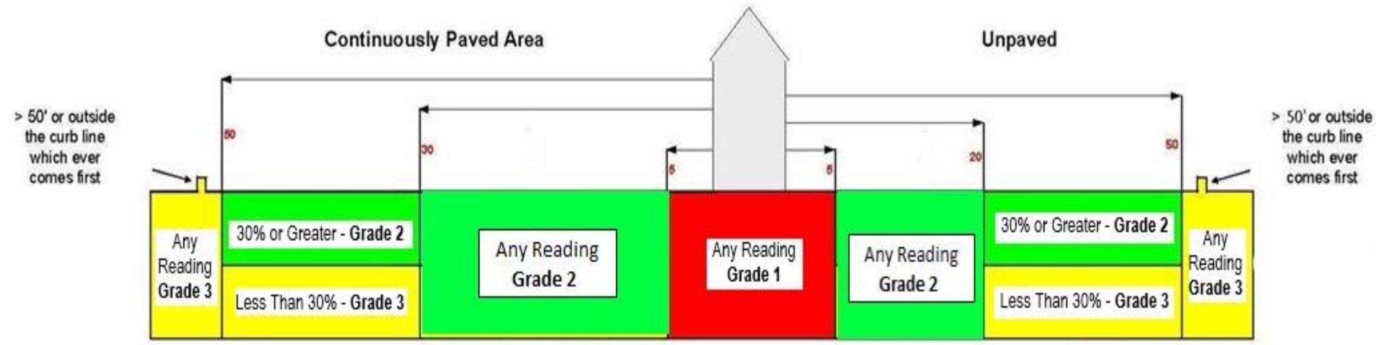
Pipeline Safety: Gas Pipeline Leak	)	**Docket No. PHMSA-2021-0039**
Detection and Repair	)	**PHMSA-2024-0005**
	)	**RIN: 2137-AF51**

APPENDIX A
TO THE
COMMENTS OF
THE ASSOCIATIONS

Example of Proximity-Based Leak Grading Regime

Dated: April 29, 2024

Leak Classification Guide



Manholes, Vaults and Catch Basins