April 29, 2024

US Department of Transportation
Docket Management System
West Building, Ground Floor, Room W12-140
1200 New Jersey Ave., SE
Washington, DC 20590-0001

Attention: Docket No(s). PHMSA-2023-0061
PHMSA-2024-0005

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

Via Email

Dear Sir or Madam:

The Northeast Gas Association[1] ("NGA") respectfully submits the following comments and request for consideration in amending regulatory text associated the abovementioned Dockets following meetings of the Gas Pipeline Advisory Committee (GPAC) regarding the proposed Leak Detection and Repair Rule (LDAR).

While the GPAC meeting provided an opportunity for the Committee to explore and consider a variety of perspectives from stakeholders, including public comments provided by NGA members, there remain several areas of further clarification and options for alternate regulatory text that we believe would benefit our shared goals of enhancing public and environmental safety associated with gas pipeline operations. Furthermore, while all regions of the country will be impacted significantly by this NPRM, the northeast region and our members serving northeast consumers, we believe, are generally disproportionally impacted. These disproportional impacts are due to the nature of historical operations and assets, the complexity of urban subsurface infrastructure all compounded by the evolving policy environment in which our members conduct business coupled with the complexity of overlapping jurisdictional regulatory change that has already taken place or is being considered.

[1] NGA is a regional trade association that focuses on pipeline safety and safety culture, education and training, technology research and development, operations, planning, and increasing public awareness of natural gas in the Northeast U.S. NGA supports a culture of pipeline safety and environmentally responsible energy delivery practices. NGA represents natural gas distribution companies, transmission companies, liquefied natural gas suppliers and associate member companies. Its member companies provide natural gas service to 14 million customers in 9 states (CT, MA, ME, NH, NJ, NY, PA, RI, VT).

NGA and its members are committed to playing a leading role enabling and accelerating the transition to a clean energy future, while ensuring all customers and communities continue to have affordable and reliable options to heat their homes and run their businesses. To that end, NGA shares PHMSA's goal of reducing emissions from our gas systems. NGA believes natural gas and the associated extensive infrastructure network support this transition while continuing as a cornerstone of America's energy economy and will continue to add value into the future. Today, hundreds of millions of Americans rely on natural gas infrastructure and the energy it delivers to heat their homes, power their businesses, and manufacture goods. Policymakers' focus on climate change and reducing emissions complements the natural gas utility industry's dedication to safety and reliability and therefore, has enabled a steep decline in methane emissions through pipeline replacement and modernization efforts. The successful collaboration of policymakers has allowed for the achievement of parallel goals, infrastructure modernization and emission risk reductions. This is best summarized in the 2020 NARUC report Natural Gas Distribution Infrastructure Replacement and Modernization: A Review of State Programs[1].

NGA and our members are committed to working with policymakers in applying a *good science common sense approach* to reducing GHG emissions through smart innovation, new and modernized infrastructure, and advanced technologies that maintain reliable, resilient, and cost-effective energy service choices for consumers. In collaboration with policymakers and regulators, NGA members continuously invest in the modernization of the northeast regional natural gas delivery infrastructure to distribute safe, reliable, and cost-effective energy in an environmentally responsible manner. As a result, methane emissions from natural gas distribution systems across the country have declined by 70 percent from 1990 – 2021.[2] The data reflects the work NGA member gas utilities have been doing to modernize their systems and implement leading practices.

While NGA understands and supports PHMSA's position to address the intent of the Pipes Act of 2020 and where reasonable, enhance existing pipeline safety regulations to address emission risks as well as public safety risk, as discussed at GPAC, several of PHMSA's proposals conceptually overlap with existing industry voluntary programs (e.g., EPA STAR Program) as well as fundamental regulatory requirements of EPA in 40 CFR Part 98 Subpart W. As a result, NGA urges PHMSA to reconsider these proposals through the lens of overlapping requirements in its final rule to further extract the greatest degree of public safety and emissions mitigation value from any rule enhancements.

NGA continues to work collaboratively and supports comments of the American Gas Association ("AGA"), American Public Gas Association ("APGA"), Interstate Natural Gas Association of America ("INGAA"), American Petroleum Institute ("API"), GPA Midstream, and American Fuel & Petrochemical Manufacturers ("AFPM") (jointly "the Associations") and other participating organizations in further developing Joint Industry Comments supported by a broad spectrum of stakeholders from across the industry. NGA supports the Associations conclusions that there must be a balance between prescriptive regulations and a performance-based approach that enables operators the flexibility to take necessary actions to ensure safety and reduce methane emissions, while delivering gas reliably and affordably to residential consumers, businesses and energy producers of the northeast region who depend on natural gas as an essential energy source.

[1] National Association of Regulatory Utility Commissioners (NARUC) Report January 2020
[2] *See* 2023 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020 (April 15, 2023) (2022 GHGI).

These supplemental comments do not replace previously filed comments on the LDAR NPRM by the NGA[3]. As with the Associations, NGA hopes that these supplemental comments will assist PHMSA as it drafts a final rule that takes a *good science/common sense* approach to advancing pipeline safety while reducing methane emissions from natural gas pipeline systems.

General Comments:

1. Leak Detection and Repair Final Rule Compliance Deadlines and Management of Change

PHMSA originally proposed only a six-month effective date for the provisions within the NPRM. As discussed at GPAC including public comments from several operators describing the complexity of multiple, significant, and simultaneous changes that will be required to comply with the final rule, six-month is simply unrealistic. The proposed requirements include a broad range of changes to operator's procedures and will result in substantial management-of-change process considerations for data collection practices, work management systems, information technology systems, equipment, staffing, training, labor union contract negotiations/agreements and Operator Qualification ("OQ") programs. These changes are comprehensive and operators will need significantly more than six months to complete all the necessary actions to ensure compliance and to maintain public safety. For example, these changes will require a restructuring of how patrols and surveys are performed in the natural gas industry, potential restructuring of previously approved rate-based pipe replacement programs and how leaks are graded and ultimately addressed. Proposing a uniform effective date of six months is not reflective of the complexity of various components of the proposal and does not address the myriad of management-of-change considerations necessary to ensure sustainable results the proposal is intended to provide.

As proposed by GPAC, 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 NGA's insistence, as with the Associations, that a full 36 months is necessary to prepare to comply with all aspects of this rulemaking.

NGA is supportive of a logical phase-in glidepath approach to the final rule, agreed to by the Committee, with an 18-month compliance planning provision and an overall effective date of 36 months from the publication date of the final rule with compliance timelines beginning on the nearest January 1st. The 18-month evaluation and planning period will allow operators to effectively reevaluate current procedures, work practices and compliance plans and make staged adjustments to meet to 36-month effective date. As a practical matter, operators will be

[3] See comments by the Northeast Gas Association Docket No. PHMSA-2021-0039, August 16, 2023.

developing procedural changes in parallel with on-going existing mandated compliance requirements and associated procedures. While some transitional changes will be implemented on the effective date, some will occur prior to this date which may be at odds with existing mandated compliance programs where jurisdictional regulatory requirements do not become effective until the 36-month date. Operator implementation dates may vary within the overall 36-month compliance effective date as the complexity of the phase-in period is commensurate with the nature of organization specific assets and operations as well as the ability for state jurisdictional regulatory changes.

As previously suggested in NGA's comments, some form of regulatory relief, such as a stay of enforcement, and acknowledgement of the complexity and variability of the transitional phase of implementing the rule is recommended to avoid any incidental and administrative non-conformance issues. In addition, the final rule must recognize the state jurisdictional process for cost recovery as these changes will bring significant cost implications not necessarily identified in the PRIA as identified in prior comments. Rate relief will be necessary to achieve our parallel goals of regulatory transition and as you're aware, these processes and associated policy complexities vary by jurisdiction. In summary, setting clear compliance expectations and implementing regulatory relief "tools" during the transition period will help both operators and state jurisdictional regulators focus on transition success rather than apparent compliance conformance inconsistencies during the transition. This understanding and relief will provide operators and jurisdictional regulators with the flexibility they need to effectively transition procedures, work practices and state regulatory requirements in balance with meeting the 36 month effective date.

Finally, GPAC agreed that PHMSA must address the issues and concerns raised by the Committee to address those leaks that exist before the compliance date of the rule. As discussed at GPAC in detail, NGA agrees with the Associations in that 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 should 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 should not 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 an existing leak graded 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/jurisdictional regulator 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. Leak Survey – Distribution

For inside jurisdictional service line piping, preserving a 5-year leakage survey frequency is appropriate and fit-for-purpose.

NGA supports the Associations comments that for 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 Final Rule[4] amending the minimum frequency of atmospheric corrosion inspections, 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 to the new 5-year inspection interval to distribution service lines.*

[4] Pipeline Safety: Gas Pipeline Regulatory Reform. Final Rule. 86 FR 12834. March 5, 2021.

> *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"*[5]

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, 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, where non-business district leakage surveys are currently performed on a five-year basis. Some of these urban operators have participated in a comprehensive study conducted by the Gas Technology Institute (GTI) study[6] 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 survey 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 summary, disallowing a five-year leakage survey interval for jurisdictional inside piping would significantly increase costs in return for negligible safety benefits.

[5] FR at 2223.
[6] Ersoy, Daniel & Farrag, Khalid. 2018. GTI Project 21858, *"Indoor Atmospheric Corrosion and Leak Survey Risk-Based Intervals".*

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

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 survey of gas distribution, transmission, and regulated gathering pipelines.

As the NGA and Associations stated previously[7], 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. For a vast majority of regulated natural gas distribution 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. Operators should be free to choose any tool that meets PHMSA's prescribed performance standard, and meets all calibration requirements, to be in compliance with the regulation.

In summary, PHMSA should adopt a clear and unambiguous set of required instrument sensitivities and *allow operators to select and use equipment that meets the appropriate sensitivity criteria,* 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.

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 with prior comments, NGA agrees with the Associations that:

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

[7] 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.

Agency[8] and Underwriters Laboratory Standards for Safety[9] 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.

The GPAC has recommended "consideration of an alternative [ALDP Performance Standard] for inside piping"[10]. 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).

NGA additionally highlights 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.

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"[11] and the appropriateness of a 500 ppm (1% LEL) minimum sensitivity for Combustible Gas Indicators (CGIs). NGA fully supports the Committee recommendations.

PHMSA should allow for the use of CGI equipment, as it is the primary device used in the industry and is fit-for-purpose 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, NGA calls PHMSA's attention to 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.

Finally, for purposes of this NPRM, PHMSA should consider clarification of gas indication units of measure and adopt a standardized approach when referring to gas leak concentrations.

[8] National Fire Protection Agency, NFPA 715 Installation of Fuel Gases Detection and Warning Equipment.
[9] Underwriters Laboratories, UL 1484 Standard for Residential Gas Detectors and UL 2075 Standard for Gas and Vapor Detectors and Sensors.
[10] See GPAC Voting Slide # 17 – Advanced Leak Detection Program Elements and Performance Standards. ALDP for gas transmission and gathering lines; Bullet #4.
[11] See GPAC Voting Slide # 17 – Advanced Leak Detection Program Elements and Performance Standards. ALDP for gas transmission and gathering lines; Bullet #4.

Expressing flammable gas indications utilizing percent gas-in-air measures (generally 5 – 15% for natural gas and for LPG 2 – 10%) rather than percent of the lower explosive limit (LEL) will ensure a consistent approach to compliance conformance among operators and eliminate confusion when reporting concentrations.

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 regulated gathering pipeline appurtenances. PHMSA should extend this fit-for-purpose allowance to above-ground gas distribution pipeline appurtenances such as inaccessible surveys locations such as inaccessible elevated piping and process vessels, LNG storage and liquefaction facilities.

PHMSA should allow for use of leak detection fluid (a.k.a. "soap solution") as a valid ALDP leakage survey methodology, across all assets.

NGA supports the Associations' NPRM comments regarding the use of leak detection fluid (a.k.a. "soap solutions") [12], 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 a definitive volumetric/mass flowrate, it is a proven fit-for-purpose technique and 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. Finally, EPA Method 21 Determination of Volatile Organic Compound Leaks listed the soap solution test as an approved leak detection screening procedure.

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

NGA supports the prior Associations NPRM comments[13], regarding limitations of the Congressional mandate for evaluation of ALDP performance (as per PIPES Act 2020 Section 113). 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

[12] 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.
[13] *Id.*, pg. 95

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. Additionally, continual evaluation and implementation of new technologies may create a higher likelihood of error, false positives, and missed identification of leaks due to a lack of technology continuity.

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 gas distribution pipelines.[14] 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.[15] As with the Associations, NGA acknowledges

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 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, NGA agrees with the Associations recommendation 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.

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

NGA supports the Associations comments regarding ALDP survey frequency in that 49 CFR 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 surveys, then that concept should have been proposed in the NPRM, commented on by the

[14] [14] See GPAC Voting Slide # 17 – Advanced Leak Detection Program Elements and Performance Standards. ALDP for gas distribution pipelines; Bullet #1, Sub-bullet #1.
[15] [15] See GPAC Voting Slide # 22 – Leak Grading and Repair. Grade 2 leaks; Bullet #1.

public, and discussed by the GPAC. None of those activities occurred, and therefore the NGA strongly recommends that this section be removed from the final regulation. Finally, operators know their systems and are free to implement more frequent leak surveys as a preventative and mitigation measure based on the conditions being observed and in accordance with an operators DIMP.

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, beyond reviewing a manufacturers or service providers approved written specifications and instructions, 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).

4. Leak Grading and Repair

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

NGA remains concerned that 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[16].

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[17], "an estimated leakage rate of 100 kg/hr or above

[16] 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."

[17] See GPAC Transcript November 30, 2023.

is unknown on gas distribution systems". NGA supports the Associations recommendation in that 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 be both unnecessary and unreasonable, with no benefit to pipeline safety or emissions mitigation.

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

NGA agrees with the Associations comment regarding[18] in that it is not appropriate to describe the non-zero greenhouse gas contributions of a Grade 2 leak as posing "significant harm to the environment." Such a descriptor is neither accurate nor proportional to the real environmental significance of a single non-hazardous leak. As it relates to emissions criteria for leak grading, PHMSA should limit the regulatory text to describing objective thresholds for leak rate, leak extent, or equivalent.

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 are redundant to, 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 regulated gathering pipelines located in HCA, Class 3, or Class 4 locations, as per § 192.760(c)(3).

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

Like the Associations, NGA acknowledges 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

---

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."

[18] 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.

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"). Arguably, the threshold for assessing the potential environmental significance of *any* leak is 10 scfh. Requiring a Grade 3 threshold of half this value (5 scfh) will result in leaks of little significance being prioritized for repair. Consequently, from an engineering perspective, the practical environmental benefits are diminished considering the total carbon footprint of the repair process relative to the option of addressing mitigation in a state approved pipe replacement schedule. Requiring operators to further develop and follow a written methodology for evaluating Grade 3 leaks for accelerated repair is onerous and unnecessary.

NGA, like the Associations, also question the need to further prioritize the repair schedule of these small leaks. The leak grading criteria is in and of itself a prioritization of repairs. Operators also inherently prioritize leak repairs as part of DIMP which considers multiple factors, including risks to public safety, proximity to other pipeline construction projects, and alignment with other public improvement projects 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.

PHMSA should make clear that the criteria for evaluating potential 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, NGA and the Associations proposed a multi-method set of criteria against which the potential environmental significance of graded leaks could be evaluated. This contrasted with PHMSA's blanket 10 cfh criterion for Grade 2 leaks, as proposed in § 192.760(c)(1)(vii)[19]

The Committee supported a version of the NGAs' and the Associations' multi-method approach[20], including evaluating leaks based on (1) estimated leakage rate in scfh, (2) leak extent (in square feet) of underground leaks, or (3) alternative methods, with notification to the appropriate agency as per § 192.18. This multi-method approach provides operators operators the necessary flexibility to assess the potential 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) instead of mandating use of a methodology based on estimated leakage rate.

However, 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 for each leak in determining potential 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

---

[19] NPRM at 31976.

[20] 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."

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 potential environmental significance of a leak.

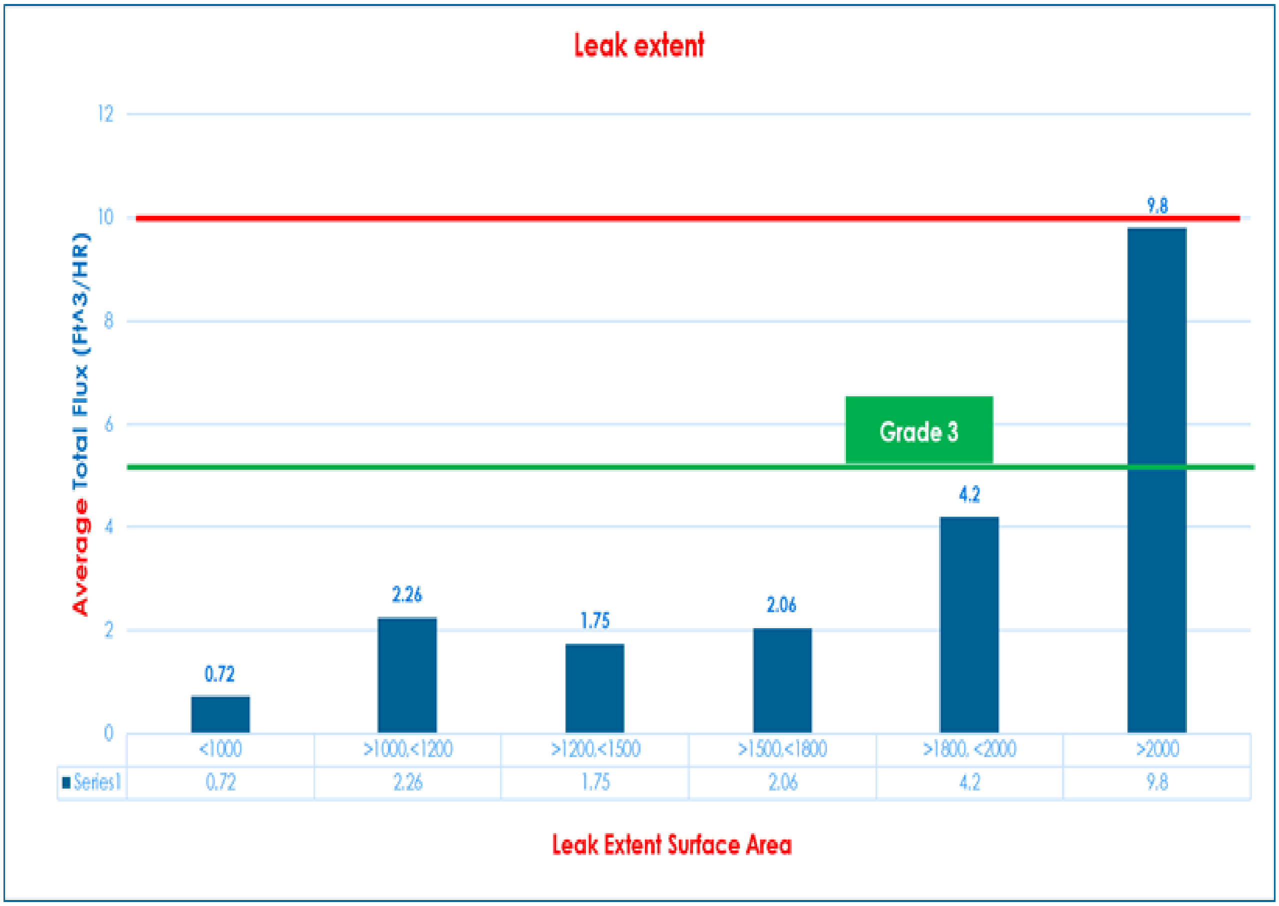
A menu of the methods should be available to operators for evaluating the potential environmental significance of Grade 3 leaks.

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 potential 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[21] and recommended for incorporation into § 192.760(c) by the GPAC[22], is based on the 2017 Large Volume Leak Study[23]. 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,"[24] a 2018 Harvard University Masters thesis 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 NGA and Associations from the study raw data). 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).

[21] FR at 31919.
[22] See GPAC Voting Slide #22 – Leak Grading and Repair.
Slide # 22, Bullet #4.
[23] "Large Volume Leak Study," 2017. Home Energy Efficiency Team. https://heet.org/gas-leaks/large-volume-leak-study/
[24] 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



PHMSA should harmonize timing of leak repair completion with its own understanding of when post-repair leak re-checks.

PHMSA acknowledged[25] during the GPAC Meeting that the primary scenario in which post-repair leak re-checks (as proposed in § 192.760(e)) are 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. NGA, as with 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.

---

[25] 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 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."

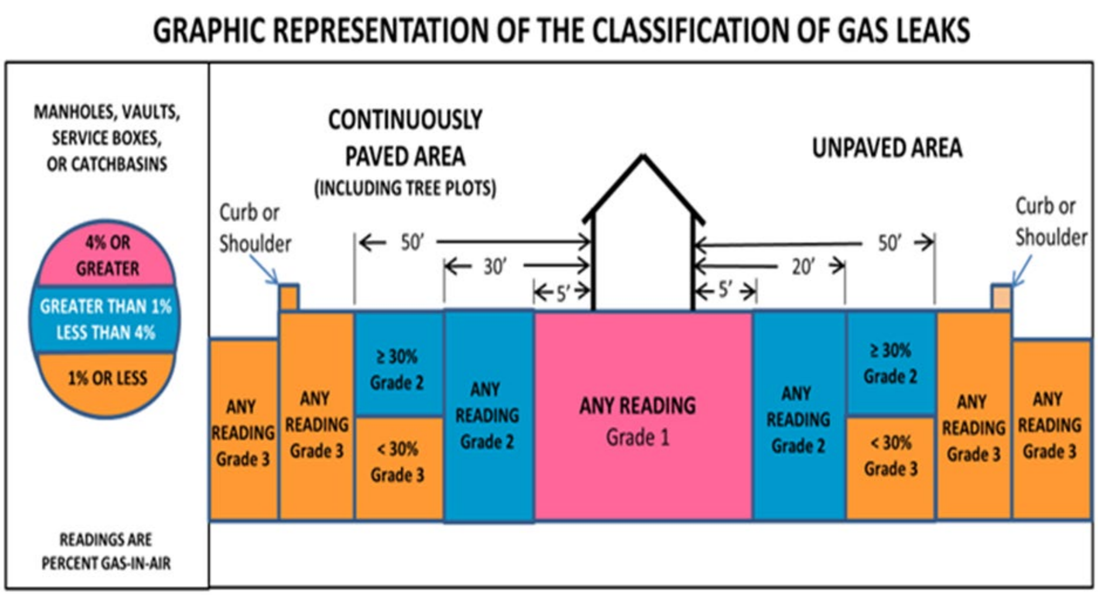
Accordingly, the provision stating that a repair is not "complete" until 0% gas readings are achieved is not valid and may create misinterpretations for demonstrating compliance with repair intervals prescribed in § 192.760.[26]

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.

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, PHMSA 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[27]. These additional criteria have provided operators with an important means of prioritizing certain leaks (via grading), particularly in wall-to-wall paved areas.

NGA and the Associations encourage PHMSA to further consider the proximity criteria already adopted by these State regulations to determine if any further grading distinction is appropriate for leaks in wall-to-wall paved areas. An example of state approved criteria[28] which considers gas indications relative to a distance from a structure, arguably an essential criterion in assessing public safety risk, aligned with PHMSA's proposed leak classification structure, is highlighted below:



[26] 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.
[27] See comments by the Northeast Gas Association Docket No. PHMSA-2021-0039, August 16, 2023.
[28] New York State Leak Grading Criteria adopted to illustrate the risk-based approach to assessing leak indications relative to distance from a building or structure in 16 NYCRR Part 255.

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.

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.

5. Reporting

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 flowrate-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 more than 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
- Proportional release from a relief valve on a commercial meter set

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.

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

NGA supports the Associations recommendation 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.

NGA requests 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.

Annual Report due date should be extended to June 15th

NGA supports 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.

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

NGA, as with 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**.**

6. LNG

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.

NGA supports the Associations recommendation to modify 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, while liquefaction facilities typically incorporate permanently installed emergency flaring capability, the systems are not generally adaptable to temporary connections for flaring unplanned vented emissions not originally considered in the emergency vent/flare system. Industry recommends that PHMSA study this issue and provide additional methane reduction options for these facilities through its LNG Center of Excellence.

NGA supports the Committee recommendation to align LNG leak detection technology sensitivities to those proposed for transmission pipelines and EPA OOOO requirements. GPAC recommended a grading and repair requirement for LNG facilities that would be similar to the proposed § 192.760 for LNG facilities. In addition, as a practical matter, close proximity leak investigations and above-ground process piping surveys are typically conducted utilizing a handheld portable combustible gas detection instrument with a 500ppm (1% LEL) detection threshold similar to EPA Method 21 requirements.NGA further supports a tailored leak grading and repair requirement for LNG facilities as stipulated in Associations proposed regulatory text. Furthermore, in addition to the Associations proposed regulatory text, NGA requests that further consideration should be given to clarifying regulatory text regarding gas indications in a *confined space*. More appropriately, regulatory text clarifications recommended include:

(v) *Any reading of 4% gas in air concentration in an enclosure not normally containing LNG or natural gas; ……..*

(i) *A reading between 1% and 4% gas-in-air concentration in an enclosure not normally containing LNG or natural gas.*

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.

NGA also supports the Associations proposal 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 an LNG site is a *maritime import/export facility.* Such import/export facilities are much larger in size and scale of operations thus subject to a variety of venting scenarios during loading / unloading of LNG cargo ships in continuous operation as compared to most peak-shaving facility operations.

Finally, the leakage survey requirements to mobile or temporary LNG facilities is unnecessary. Mobile and temporary LNG facilities are often relocated, reconnected, and repressurized, and there is no indication in the record that these non-stationary LNG facilities are a significant source of methane emissions. The Proposed Rule also appears to overlook the exception from Part 193 applicability for mobile and temporary LNG facilities that comply with the standards in 2001 NFPA 59A, which would not be subject to the proposed leakage survey requirements in any event.

7. Operator Qualification

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

NGA supports the Associations previously provided comprehensive comments as to why the introduction of § 192.769 is redundant and could cause considerable regulatory confusion.[29]

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

[29] 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.

individuals be trained in tasks they are not responsible for."[30] NGAsupports this stance and reaffirms 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.

8. Investigation of Failures

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

NGA as with the Associations would like to 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'"[31], which are 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., 3rd party laboratories and operator personnel), and would unquestionably diminish the effectiveness and importance investigating failures considered significant by the operator.

NGA supports the GPAC's recognition of the importance of making a clear distinction between failures and (most) leaks.[32] 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."
As a result, NGA supports, as with the Associations, a clarified definition of "Failure" in § 192.617 *Investigation of failures and incidents*. For the purposes of this section, the term failure should be clarified to mean **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.

9. Definitions

Proposed Definitions Supported by Associations and NGA

While not discussed during the GPAC meeting, but highlighted during the public comments, NGA requests PHMSA to consider clarification of 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 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.

---

[30] See GPAC Slide # 87 – Operator Qualifications - § 192.769. Bullets #2 and #3.
[31] 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.
[32] 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."

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.**

"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.
NGA, as with 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*[33] not out of a concern for proximity to people, but 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 surveys 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. NGA as with the Associations oppose defining this term within 49 CFR 192.

Definitions not necessary for this rulemaking

NGA does not believe it is necessary for PHMSA to codify a definition for *leak* or *hazardous leak*. As a result of the proposed leak grading criteria in § 192.760, the distinction between a hazardous leak and leak is defined in the grading regime.s Therefore, an additional definition is not necessary, and would only cause confusion for the regulated community.

---

[33] 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.

Conclusion

NGA appreciates the opportunity to comment on the proceedings of the GPAC Meeting. NGA remains committed to working with PHMSA in achieving our parallel goals of maximizing pipeline and environmental safety through a collaborative process.

Respectfully submitted,

Paul Armstrong

By: Paul Armstrong
Vice President of Operations
Northeast Gas Association
1800 West Park Drive, Ste 340,
Westborough, MA, 01581
parmstrong@northeastgas.org
(781) 455-6800 ext.1130

For further information please contact
Robert Wilson
Vice President Special Projects
Northeast Gas Association
bwilson@northeastgas.org
(607) 643-5111