August 16, 2023

<u>Submitted via www.regulations.gov</u>

Mr. Sayler Palabrica
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
1200 New Jersey Avenue SE, PHP-30
Washington, D.C. 20590

Re: Comments on Gas Pipeline Leak Detection and Repair NPRM
Docket No. PHMSA-2021-0039

Dear Mr. Palabrica:

The Interstate Natural Gas Association of America (INGAA), a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry in North America, respectfully submits these comments in response to the Pipeline and Hazardous Materials Safety Administration's (PHMSA) "Pipeline Safety: Gas Pipeline Leak Detection and Repair" proposed rule (the NPRM or Proposed Rule).[1] INGAA is comprised of 26 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.

INGAA participated in and supports the joint comments of the American Gas Association, American Petroleum Institute, GPA Midstream, the American Fuel & Petrochemical Manufacturers, and the American Public Gas Association (the Joint Trades). INGAA also submits the attached comments to further document its positions and provide an analysis of the Preliminary Regulatory Impact Analysis as it relates to gas transmission pipelines.

INGAA appreciates your consideration of these comments.

Respectfully submitted,

Ben Kochman

Ben Kochman
Director of Pipeline Safety Policy

[1] Pipeline Safety: Gas Pipeline Leak Detection and Repair, 88 Fed. Reg. 31,890 (May 18, 2023).

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 No. PHMSA-2021-0039

COMMENTS IN RESPONSE TO GAS PIPELINE LEAK DETECTION AND REPAIR NOTICE OF PROPOSED RULEMAKING

FILED BY
THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

August 16, 2023

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I. Executive Summary

INGAA supports PHMSA's efforts to prescribe gas pipeline leak detection and repair regulations pursuant to the requirements in Section 113 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (the PIPES Act).[2] However, INGAA urges the agency to reconsider several of its proposals and reevaluate the costs and benefits associated with the NPRM. Of note, INGAA has provided a detailed analysis of the agency's calculations and conclusions in the Preliminary Regulatory Impact Analysis (PRIA).[3] *See* Exhibit A. INGAA estimates that the costs for gas transmission operators to comply with these new proposals will range between $228 to $516 million annually.[4] These cost totals are a stark contrast to PHMSA's assumption of $14.9 million per year. In terms of the benefits associated with the Proposed Rule, PHMSA's cost effectiveness value of the NPRM is $23,763 per metric ton of methane. INGAA performed similar calculations and determined the cost effectiveness ranges between $363,636 to $822,967 per metric ton of methane. Given the significant delta between PHMSA and INGAA figures, the association recommends that PHMSA review INGAA's analysis and recalculate the costs and benefits associated with the NPRM.

INGAA supports the Joint Trades' comments and highlights the following modifications that are of particular importance to its members:

- Allow a three-year effective date to implement the proposed requirements in the final rule.
- Allow flexibility to use different technology and methods fit for purpose to detect and pinpoint leaks.
- Accept the Joint Trades' definition of a leak.
- Permit transmission operators to use a grade 3 classification for certain leaks and extend the repair timeframes for grade 2 leaks.
- Use the date of discovery for determining when an unknown leak started and acknowledge that not all leaks warrant a failure investigation.
- Reevaluate whether operators of compressor stations need to comply with the NPRM until the EPA OOOOb and OOOOc rules are finalized.
- Determine the need for a recordkeeping provision in section 192.703(d) if the facility is exempted from the Part 192 subpart M requirements.
- Set a minimum required patrol frequency of 6 times per calendar year but also allow operators to use a risk-based alternative.
- Expand the exception for emergencies to include safety risk and commercial impacts.

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[2] Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020, Consolidated Appropriations Act, 2021, Division R, Pub. L. 116-260, 134 Stat. 1181, 2210.
[3] PHMSA, Preliminary Regulatory Impact Analysis, Docket No. PHMSA-2021-0039 (April 2023), *hereinafter, "*the PRIA", https://www.regulations.gov/document/PHMSA-2021-0039-0019.
[4] *See* Table 1 of Exhibit A.

II. Effective Date

PHMSA should provide a three-year effective date for the Final Rule. The six-month timeframe proposed in the NPRM is not realistic or achievable. In comparison, Congress provided operators with one year to include the new section 114 requirements in their operation and maintenance procedures. The proposed modifications in the NPRM reflect a more impactful set of changes. Operators will need to create new compliance programs, hire and train contractors and new company personnel, modify equipment, and revise procedures. If finalized as proposed, the majority of the advanced technology providers will not be able to meet the sensitivity requirements and the increased demand. PHMSA should provide additional time for these providers to ramp up and for operators to acquire the necessary equipment.

INGAA specifically seeks a three-year effective date for consistency with EPA's OOOOc rulemaking[5] and to assist operators in addressing the proposed compressor station exception in § 192.703(d)(1)-(3). PHMSA has stated in the NPRM that its section 192.703 exception would not apply until the EPA rule is finalized. PHMSA failed to consider that it could take three or more years before compressor stations would be regulated under the State or Federal plans created to implement these EPA standards. Under EPA's proposed 40 CFR part 60, subpart OOOOc requirements, a State or Federal plan that creates the methane emission monitoring and repair requirements for existing compressor stations across the United States may not apply until three years after EPA issues a final rule promulgating the 40 CFR part 60, subpart OOOOc emission guidelines.[6] A three year effective date for the PHMSA rule would allow operators with these specific facilities to focus solely on the EPA requirements rather than first setting up a program in compliance with PHMSA regulations and then switching at a later date to an EPA program.

INGAA anticipates that a reasonable effective date will also greatly reduce the number of requests PHMSA may receive from operators to deviate from the timeframes prescribed for Grade 2 and Grade 3 leak repairs. Finally, PHMSA should take into account the competing effective dates and obligations of several PHMSA and EPA rules with similar timeframes.[7]

The Agency's position that the six-month effective date is reasonable because industry has "the time since the issuance of [the] NPRM" is not supported by law. PHMSA cannot expect operators to expend resources on the basis of a proposal. The purpose of an effective date is to allow affected parties to prepare and take action in response to the final rule. Federal courts have determined that the "required publication" of substantive rules as directed in the Administrative Procedure Act is

[5] 40 CFR part 60, subpart OOOOc.

[6] Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 87 Fed. Reg. at 74,721.

[7] *See* MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments (Final Rule) Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments (Final Rule); Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments (Final Rule); EPA's Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (Proposed Rule); EPA's Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems (Proposed Rule); and Requirement of Valve Installation and Minimum Rupture Detection Standards (Final Rule).

a reference to the final rule and is not satisfied by the publication of a notice of proposed rulemaking.[8] Operators cannot begin implementation efforts until they know the exact requirements in the Final Rule. There were key differences between the NPRMs and the Final Rules issued by PHMSA in recent years. If industry had committed funds on the basis of some of those proposals, it would have had to redo certain efforts. For these reasons, INGAA strongly recommends that PHMSA provide a three-year effective date of the final rule. Consistent with the Joint Trades' comments, the three-year effective date should begin on the first day of the calendar year following publication.

III. Technical Comments

A. Proposed Reporting Requirements

1. Large-Volume Gas Release Reporting

In proposed section 191.19, PHMSA introduces a requirement for operators of all jurisdictional gas pipeline facilities to submit reports of intentional and unintentional gas releases of 1 million cubic feet (MMCF) or more.[9] PHMSA should reevaluate its estimated paperwork burdens to complete such reports, adjust the deadline for filing the reports, and clarify that incident reports and large-volume gas release reports are parallel but separate efforts.

a. PHMSA's methodology for calculating the number of Large-Volume Gas Release Reports per year is not clear.

PHMSA acknowledges that it "does not have information on the current number of leaks between 1 and 3 MMCF."[10] In the NPRM, PHMSA estimates that it would receive 373 total reports on average each year, including 134 for transmission.[11] In the Preliminary Regulatory Impact Analysis (the PRIA), the agency estimates that it would receive 393 total reports per year (139 reports for transmission).[12] PHMSA calculates these figures by estimating that 8% of 1,740 leaks (defined as the average number of leaks reported between 1 MMCF and 3 MMCF) would qualify as a large-volume gas release.[13] PHMSA has not explained its rationale for using 8%. The agency stated that it assumed 8 percent is the correct figure based on "incident reports of unintentional releases of natural gas between 1 and 3 MMCF."[14] PHMSA did not provide any supporting data to support its use of 8%. INGAA cannot provide meaningful comment without understanding PHMSA's analysis.

b. PHMSA should review its estimate of the burden to complete each Large-Volume Gas Release Report.

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[8] *Ctr. for Marine Conservation v. Brown*, 917 F. Supp. 1128, 1153 (S.D. Tex. 1996); *Ngou v. Schweiker,* 535 F. Supp. 1214, 1216 (D. D.C. 1982); *Rowell v. Andrus*, 631 F.2d 699, 702 (10th Cir. 1980); *U.S. v. Gavrilovic*, 551 F.2d 1099, 1103-04 & n.9 (8th Cir. 1977).
[9] Proposed section 191.19.
[10] PRIA, at 51.
[11] Pipeline Safety: Gas Pipeline Leak Detection and Repair, 88 Fed. Reg. 31,890, 31,967 (May 18, 2023).
[12] PRIA, at 51.
[13] PRIA, at 51.
[14] PRIA, at 51.

PHMSA's estimate of the burden (the time, effort, and financial resources)[15] involved in completing a Large-Volume Gas Release Report is not clear and, at times, inconsistent. The agency has an obligation to engage in a "specific, objectively supported estimate of [the] burden" imposed by a proposed information collection.[16] PHMSA must analyze the time and cost to (1) review instructions; (2) develop, acquire, and install technology to collect, verify, and process the requested information; (3) train personnel; (4) search existing data sources; (5) complete the form; and (6) submit the information to the agency.[17] In the Proposed Rule, PHMSA estimates that it will take an operator only four hours to complete these tasks.[18] In the PRIA, the agency provides a different burden estimate indicating that it will take each operator twelve hours.[19]

Each operator will need sufficient time to acquire the necessary technology, train personnel, perform calculations to determine reporting applicability, complete and submit the report, and respond to PHMSA and state inquiries, PHMSA should reevaluate its cost assessment for completing these reports and publish a risk assessment that explains its use of the 8%, how it calculated the projected number of reports that will be filed, and ensure that it has included all of the steps needed to complete such an information collection.

c. PHMSA should use technology to reduce the burden of this information collection.

PHMSA should consider modifying its collection method to reduce the burden. The agency is required to assess whether the burden on paperwork collection respondents can be reduced through technology.[20] The agency should consider using a tabular reporting process within the PHMSA Portal for Large-Volume Gas Releases. By using a table that could be consistently updated, operators could populate and revise the data more efficiently. This type of approach would decrease the paperwork burden compared to requiring operators to create individual stand-alone submissions. INGAA requests that PHMSA consider these comments and re-evaluate its burden estimate to confirm that it complies with 5 C.F.R. Part 1320.

d. PHMSA should use the date of discovery for determining when a leak started.

The agency provides in the NPRM that "[i]f the time the leak started is unknown, operators should base the calculation based on estimated release volume from the date of the most recent leakage survey."[21] PHMSA provides no support for this position and only makes this statement in the preamble. The agency does not include this language in the proposed Instructions for the Large-Volume Gas Release Report. The purpose of reporting requirements is to collect accurate data. Requiring an operator to calculate the estimated release volume from the date of its last leakage survey will produce unsupportable data.

[15] 5 C.F.R. § 1320.3(b)(1).
[16] 5 C.F.R. § 1320.8(a)(4).
[17] 5 C.F.R. § 1320.3(b)(1)(i)-(ix).
[18] 88 Fed. Reg. at 31,967.
[19] Preliminary Regulatory Impact Analysis (PRIA), at 51.
[20] 5 C.F.R. § 1320.8(a)(5).
[21] 88 Fed. Reg. at 31,955 (emphasis added). PHMSA states in the Proposed Rule that "if the time the leak started is unknown, operators should base the calculation based on estimated release volume *from the date of the most recent leakage survey*."

PHMSA should use the date the leak is discovered as the start date for a leak, not the last leakage survey.[22] The date of the first indication of a verified leak is a far more reliable indicator of leak start date than the date of the last leakage survey. Given consistent work at pipeline facilities and in the right-of-way and odorization requirements for certain pipelines, it is far more likely that a leak began when it was first detected than at the time of the last survey date. PHMSA should clarify in its instructions for the Large-Volume Release Report that if the time the leak started is unknown, operators should base the calculation on the estimated release volume from the date of the first indication of the leak.

e. PHMSA should clarify that an operator can file a supplemental incident report rather than require both a Large-Volume Gas Release Report and an Incident Report.

Incident reports and Large-Volume Gas Release Reports should be used as parallel but separate efforts. In proposed section 191.19, PHMSA states that if events are reported as incidents, an operator would still need to file a Large-Volume Gas Release Report if the total release volume "at cessation exceeds 10% of the volume estimates in the incident report."[23] This is contrary to the agency's position in the preamble that a Large-Volume Gas Release report fills a gap in incident reporting and will serve as a parallel effort.[24]

Requiring operators to file both reports is also inconsistent with Paperwork Reduction Act requirements. Agencies must demonstrate that information collections are "the least burdensome necessary," "not duplicative of information otherwise accessible to the agency," and "ha[ve] practical utility."[25] If the volume estimate needs to be updated, an operator should file a supplemental incident report. There is no need to also file a Large-Volume Gas Release Report. This approach would lead to duplicative reporting and is overly burdensome.

f. PHMSA should allow operators to rescind a Large-Volume Gas Release Report if it subsequently meets the incident definition in § 191.3.

PHMSA states in the NPRM that "if an unintentional release reported as a large-volume gas release report subsequently becomes reportable as an incident due to updated release volume estimates or consequences (or for any other reason), the operator would have to resubmit it as an incident report appropriate for the facility type."[26] INGAA understands that reasoning but request a process for the operator to rescind the Large-Volume Gas Release Report for the same event.[27]

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[22] 88 Fed. Reg. at 31,955.
[23] 88 Fed. Reg. at 31,955.
[24] 88 Fed. Reg. at 31,967.
[25] 5 C.F.R. § 1320.5(d)(1).
[26] 88 Fed. Reg. at 31,955.
[27] The time and effort of filing such a rescission should be factored into the calculated burden for Large-Volume Gas Release Reports.

2. Annual Reports

a. PHMSA should update its paperwork burden estimate associated with completing an Annual Report.

PHMSA states in the PRIA that the existing paperwork burden for Part 192-regulated gathering and transmission pipeline annual reports is 21.5 hours and that the proposed modifications to the annual report would increase the burden by six hours.[28] However, the Office of Information and Regulatory Affairs recently reviewed and approved changes to this form and PHMSA had noted in that submission that the burden per report for each transmission operator is expected to be 47.5 hours.[29] If the six hours to complete the modifications noted in the NPRM is correct, then the burden should be 53.5 hours or more.

b. The agency should reconsider its proposed deletions in Part M1 of the Annual Report Instructions.

In Part M1 of the instructions to the Annual Report, PHMSA proposes to eliminate the important and necessary clarification that if a non-hazardous release can be eliminated by lubrication or tightening, it is a not a leak.[30] PHMSA also proposes to remove the definition of a leak.[31] As discussed in these comments, releases that can be eliminated by routine maintenance should not be considered leaks. Adding these types of releases to the leak definition would significantly increase the burdens in reporting with little to no associated benefit.

c. PHMSA should revise the deadline to file an annual report from March to June.

The current deadline for a Gas Transmission Annual Report (DOT Form PHMSA F 7100.2–1) is March 15th. Given the changes proposed in this rulemaking and the extensive modifications made to the reporting obligation over the last couple of years,[32] INGAA recommends that PHMSA move this reporting deadline to June 15th. The agency has provided additional time for annual reports in the past. In 2005, PHMSA's predecessor, the Research and Special Programs Administration, provided hazardous liquid operators until June 15th to file annual reports recognizing that the industry would need additional time to gather the requested information.[33] Hazardous liquid operators continue to have until June 15th to file annual reports each year.[34] A June deadline for natural gas operators will ease the reporting burdens and provide consistent deadlines for both natural gas and hazardous liquid operators. A June deadline should not impact PHMSA's ability to complete inspection planning for the next calendar year.

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[28] PRIA, at 51.

[29] OMB Control No. 2137-0522, concluded on March 30, 2023 (https://www.reginfo.gov/public/do/PRAViewICR?ref_nbr=202211-2137-001) .

[30] The instructions had provided that "a non hazardous release that can be eliminated by lubrication, adjustment or tightening is not a leak." Instructions for Form PHMSA F-7100.2-1 at 14.

[31] *Id.*

[32] The length of DOT Form PHMSA F 7100.2–1 has increased from two pages prior to calendar year 2010 to over 20 pages.

[33] Pipeline Safety: Hazardous Liquid Pipeline Operator Annual Reports, 69 Fed. Reg. 537, 539 (Jan. 6, 2004).

[34] 49 C.F.R. § 195.49.

B. Confined Space

PHMSA introduces a new definition of "confined space" in the NPRM. However, this definition is different from the Occupational Safety and Health Administration's (OSHA) definition of the same term.

OSHA defines "confined space" as:

> a space that: (1) is large enough and so configured than an employee can bodily enter it; (2) has limited or restricted means for entry and exit; (3) is not designed for continuous employee occupancy.[35]

PHMSA acknowledges that its definition differs from the OSHA definition and references the GPTC Guide in support.[36] However, the GPTC Guide is not regulation. While the GPTC Guide uses the phrase, "in which gas could accumulate," and the PHMSA proposed definition uses the phrase, "in which gas could accumulate or migrate," the OSHA definition has the same intent. Having to contend with two different regulatory definitions for the same term is confusing and unnecessary. Since most operators use the OSHA definition in their procedures, INGAA recommends that PHMSA either adopt the OSHA definition or use a different term.[37] Using the same term but defining it differently will create unnecessary confusion and inconsistencies in operator procedures.

C. Notifications

1. PHMSA should eliminate the reference to section 192.703(d)(4) in its proposed modifications to section 192.18(c).

PHMSA proposes to amend the section 192.18 notification provision to include a reference to § 192.703(d)(4).[38] However, there is no § 192.703(d)(4) in either the current pipeline safety regulations or proposed in the NPRM. PHMSA should correct this error in the regulatory text.

2. The agency should limit its use of section 192.18(c) in the NPRM.

INGAA is concerned that where the costs have not been evaluated in the PRIA, PHMSA may be using the no-objection process to fill the gap. PHMSA must prepare a proper risk assessment and make a reasoned determination to prescribe new requirements. The agency cannot use the no-objection process to address deficiencies in its PRIA.[39]

[35] 29 C.F.R. § 1910.146.
[36] 88 Fed. Reg. at 31,955.
[37] 29 C.F.R. § 1910.146.
[38] 88 Fed. Reg. at 31,973.
[39] *GPA Midstream Ass'n v. United States Dep't of Transportation*, 67 F.4th 1188, 1199 (D.C. Cir. 2023).

D. Proposed modifications to uprating requirements

1. PHMSA should not remove "potentially" from all Subpart J provisions.

PHMSA's proposal to strike "potentially" from all Subpart J provisions related to the detection of "potentially hazardous leaks" during pressure testing is problematic. With the understanding that all leaks are not hazardous leaks, INGAA recommends PHMSA refrain from changing qualifiers that exist in 49 C.F.R. §§192.507, 192.509 and 192.513.

2. PHMSA should allow operators to grade certain leaks in order to uprate the pipeline.

In §§ 192.553 and 192.557, PHMSA proposes to eliminate existing language that would allow an operator to monitor a non-hazardous leak and continue with uprating procedures. This is an impactful change. INGAA urges PHMSA to consider allowing 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. These leaks, when present, are typically found on pressure test headers that are not part of the pipeline placed into service following pressure testing. PHMSA's explanation for its proposal demonstrates that the agency did not consider leaks during pressure tests that are not on piping that is ultimately placed into service.[40] INGAA recommends that PHMSA refrain from making changes to sections 192.557 and 192.553 as these changes are not justified and are based upon a flawed assumption of how they are used by operators.

E. Definition of Failure and Scope of Failure Investigations

1. PHMSA should revise its proposed definition of a failure and narrow the scope of the required failure investigation.

For the purposes of section 192.617, the agency proposes that a failure is "when any portion of a pipeline becomes inoperable, is incapable of safely performing its intended function, or has become unreliable or unsafe for continued use."[41] The agency states that it based this definition on ASME B31.8[42] and that the agency's proposed definition is "consistent with industry standards".[43] However, PHMSA's definition is not consistent with the ASME definition. The agency removed important qualifiers specifying that a failure occurs when a part in service has become *completely* inoperable or *deteriorated seriously to the point that it has become unreliable or unsafe for continued use*.[44] If PHMSA intends to use the ASME definition as support, it should

[40] 88 Fed. Reg. at 31,953. "PHMSA expects the impact of those proposed revisions would be de minimis, as reasonably prudent operators would not place new, replaced, relocated, or changed pipeline segments if they had observed any leak during initial testing."
[41] Proposed § 192.617(e).
[42] 88 Fed. Reg, at 31,951.
[43] PRIA, at 16.
[44] ASME B31.8, "Gas Transmission and Distribution Piping Systems" (emphasis added).

codify that exact definition. Proposing that a failure occurs when any portion of the pipeline is 'unreliable' or 'unsafe' without the additional deterioration language is subjective, could be misinterpreted, and may be difficult to enforce. Codifying a different definition of failure from a well-recognized industry standard will create confusion and unnecessary inconsistencies.

The agency should also review its intended use of this definition. The primary focus of PHMSA's failure investigation requirement should be leaks that present a risk to life or property. All leaks should not require a failure investigation. Leaks addressed through the tightening of a fitting or a relief valve adjustment should not require a robust failure investigation. Intentional releases should also not require a failure investigation. INGAA requests that PHMSA clarify that leaks addressed through common maintenance activities or are intentional due to operational activities will not require a failure investigation or metallurgical analysis.

2. PHMSA's estimate of the costs incurred by investigating all leaks is incorrect.

PHMSA did not evaluate the costs of using the proposed definition of a failure or requiring an investigation of all leaks in the PRIA. In Table ES-1 of the PRIA, PHMSA lists the total annualized costs of proposed requirements for transmission pipelines and only lists leakage surveys, repairs, reporting, and recordkeeping as having costs.[45] There is no discussion of failure investigation costs. PHMSA must conduct a risk assessment identifying "the costs and benefits associated with the proposed standard." [46]

3. PHMSA should not include the proposed definition of failure in section 192.3 without further analysis and opportunity for comment.

In the NPRM, PHMSA invites comment on whether it should include its proposed new definition of 'failure' in section 192.3 and therefore apply this definition throughout Part 192.[47] PHMSA specifically states that it would consider making this change "in a final rule in this proceeding."[48] The agency has not evaluated the cost and benefits of making such a change and would need to do so first to satisfy its statutory obligations. The D.C. Circuit has held that "PHMSA must submit for peer review and make available for public comment a risk assessment identifying 'the costs and benefits associated with the proposed standard.'"[49] PHMSA must evaluate the impacts adding a new definition of failure throughout Part 192 prior to finalizing such an impactful change.

F. Compressor Station Exception

1. Scope of Exception

[45] PRIA, at 2. PHMSA also includes patrols but lists a zero cost for those changes.
[46] *GPA Midstream Ass'n v. United States Dep't of Transportation*, 67 F.4th 1188, 1197 (D.C. Cir. 2023)(citing 49 U.S.C. § 60102(b)(3)(B)).
[47] 88 Fed. Reg. at 31,952.
[48] 88 Fed. Reg. at 31,952.
[49] *GPA Midstream Ass'n v. United States Dep't of Transportation*, 67 F.4th 1188, 1197 (D.C. Cir. 2023)(citing 49 U.S.C. § 60102(b)(3)(B)).

a. PHMSA should expand the proposed exception in section 192.703(d) to include facilities subject to state regulations.

In proposed section 192.703(d)(1)(ii), PHMSA provides that an operator will not need to comply with sections 192.703(c), 192.705, 192.706, 197.760(a)-(h), 192.763, and 192.769 if the compressor station is subject to methane emission monitoring and repair requirements under EPA's OOOOa, OOOOb, or an EPA approved state or federal plan that is as stringent as the anticipated requirements in OOOOc.[50] PHMSA should also include state methane emission monitoring and repair requirements until a time that they are part of an EPA-approved plan. Numerous operators are subject to various state emission monitoring and repair regulations. PHMSA acknowledges the existence of these requirements in the preamble of the NPRM.[51] For efficiency and consistency purposes, PHMSA should also incorporate facilities that are subject to these state regulations in its section 192.703(d) exception.

b. Applicability of recordkeeping provision

PHMSA's proposed section 192.703(d)(3) provides that while an operator's compressor station may be exempted from PHMSA leak grading and repair requirements,[52] it would still need to maintain repair records for the life of the facility. If the compressor station is exempted from the leak grading and repair requirements in sections 192.706(a)-(h), it should also be exempt from recordkeeping requirements in section 192.706(i). Without further explanation from the agency, INGAA can only assume that PHMSA is expecting those operators with compressor stations exempted from PHMSA regulations to maintain its OOOO repair records for PHMSA purposes. This is duplicative and unnecessary.

2. Impact of finalization of EPA Rule

a. PHMSA should reevaluate its intentions to require operators of compressor stations to comply with the NPRM until OOOOb and OOOOc is finalized.

PHMSA's position on whether pipeline facilities subject to the anticipated OOOOb and OOOOc requirements will qualify for the exception in section 192.703(d) is confusing. The agency states in the preamble that "[i]n the event that EPA's proposed regulations at subparts OOOOb and OOOOc are not in effect because they have not yet been finalized or for any other reasons, the proposed exception would not apply and the leak detection, grading, and repair requirements proposed herein would apply to gas transmission and gas gathering compressor station facilities."[53] The agency also provides in footnote 245 that "should proposed subparts OOOOb and OOOOc not be finalized, only gas transmission compressor and gas gathering boosting stations subject to 40 C.F.R. part 60, subpart OOOOa would be eligible for the exception proposed in this NPRM."[54] However, in the PRIA, PHMSA states that "[a]lthough PHMSA assessed an alternative where no

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[50] Proposed section 192.703(d)(1)(ii).
[51] 88 Fed. Reg. at 31,916-31,919.
[52] *See* Proposed section 192.703(d) referencing sections 192.760(a)-(h).
[53] 88 Fed. Reg. at 31,939.
[54] 88 Fed. Reg. at 31,939, fn. 245.

such exemption would be provided, PHMSA did not propose that alternative to avoid duplicative regulation of those facilities."[55]

Operators should not be required to create a new program in compliance with PHMSA's leak detection and repair requirements only to pivot to the EPA requirements when they are finalized. This position is not reasonable, cost-effective, or practical. Instead, the agency should provide a three year effective date for the final rule in this proceeding. A longer effective date would allow those facilities that are covered by proposed section 192.703(d) to accommodate any delays in finalizing the EPA rule and prevent duplicative efforts.

If PHMSA proceeds with requiring operators of these facilities to comply with the Final Rule first and then subsequently OOOOb or OOOOc, the agency will need to incorporate these costs into its Final Regulatory Impact Analysis. In the PRIA, PHMSA examined these costs but framed them up as a regulatory alternative that the agency chose to not select.[56] This is confusing because in the NPRM, the agency has clearly chosen to proceed with applying its proposed requirements to facilities subject to OOOOb or OOOOc, if the EPA rules are not finalized at the time of PHMSA's publication.[57] The agency's estimate of the costs of eliminating the exception are $11.9 million per year. However, it is not clear if that cost estimate also included the effort to move these facilities to an EPA directed program once the OOOOb and c rules are finalized.

G. Patrolling Frequency

1. Existing Practices

a. PHMSA's assumption that all gas transmission operators currently patrol their rights-of-way (ROWs) on a monthly basis is incorrect.

PHMSA proposes that operators will need to patrol all gas transmission ROWs at least twelve times each calendar year at intervals not exceeding 45 days.[58] The assumption that all gas transmission operators are voluntarily patrolling ROWs monthly instead of the regulatory required one to four times per year is incorrect and unsupportable.[59] Not all gas transmission operators patrol their entire system monthly. In fact, not all transmission operators rely on aerial patrols to inspect their ROWs. In some cases, the pipelines are too close in proximity, difficult to fly the full length of the right-of-way, or include storage assets. Furthermore, many pipelines traverse the northeast and other regions susceptible to several months of snow cover. For those situations, many operators opt to conduct ground patrols or patrol certain ROWs via motor vehicle or all-

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[55] PRIA, at 20.

[56] PRIA, at 7 ("In the event EPA does not finalize the proposed requirements, PHMSA *could* proceed with setting equivalent requirements for gas transmission compressor stations and gathering and booting stations by eliminating the exemption"). *See also,* PRIA at 20 ("Although PHMSA assessed an alternative where no such exemption would be provided, PHMSA did not propose that alternative to avoid duplicative regulation of those facilities.")

[57] 88 Fed. Reg. 31,890, at 31,939; *See also,* 88 Fed. Reg. 31,939, fn. 245.

[58] Proposed section 192.705(b).

[59] The pipeline safety regulations currently require patrols every 4 ½ months to every 15 months depending on the location of the pipeline.

terrain vehicle. The current pipeline safety regulations allow for this flexibility.[60] Some operators use a risk-based approach and focus more frequent pipeline patrols on the riskier segments of their pipeline systems (e.g. population near the ROW, areas known for more frequent ground movement, or other specific threats to the pipeline). PHMSA supports its assumption by referencing a single operator's voluntary commitment.[61] The agency also references the practices of unnamed gas transmission operators and then concludes that "this practice is common across transmission operators."[62] INGAA's members are all gas transmission operators and can report that while some operators may choose to patrol specific ROWs more frequently than required, it is not accurate to conclude that all gas transmission operators patrol on a monthly basis.

2. Recommended Frequency

a. PHMSA should establish the minimum required patrol frequency at 6 times per calendar year.

PHMSA should establish the minimum required patrol frequency at 6 times per calendar year, not to exceed intervals of 75 days. The current requirement is between one to four times per year depending on the location. PHMSA has not supported the need to increase the frequency twelvefold. The agency also proposes that patrols must not exceed intervals of 45 days. In the winter months, certain locations in the United States become very difficult to patrol, particularly on foot. After significant snowfall, a forty-five day window may be difficult to achieve. Operators need the flexibility to balance PHMSA's goal of increasing patrols with the safety risks of requiring foot patrols in areas with potentially dangerous weather conditions. A 75-day interval is more feasible.

b. The Agency should also allow operators to choose a risk-based approach as an alternative.

INGAA recommends that PHMSA allow operators to choose an alternative patrol frequency. This risk-based approach would build upon the agency's current methodology in section 192.705. From 1975 to present day, PHMSA has established patrol frequency based on the class location of the pipeline. Operators with pipelines in more populated areas patrol more frequently than those in rural areas. PHMSA has not explained in the NPRM why this approach is suddenly deficient and instead why it is switching to a universal 12 times per year approach regardless of the location of the pipeline. The agency continues to allow leakage survey frequencies to be defined by risk and should apply the same approach to patrols. Recognizing that the pipeline safety regulations are minimum standards and operators are free to patrol more frequently than required by the regulations, PHMSA should propose the following:

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[60] Section 192.705(c)("Methods of patrolling include walking, driving, flying, or other appropriate means of traversing the right-of-way.")

[61] PRIA, at 37.

[62] The Agency states that "[g]iven baseline practices, PHMSA estimates that the proposed enhanced patrolling requirements will result in no incremental costs for onshore and offshore transmission and Type A regulated gas gathering pipeline patrol requirements under the proposed rule." PRIA, at 37-38.

Class location of line	Current Requirements (Excluding Highway and Railroad Crossings)	Recommended Increase
1	15 months, but at least once each calendar year	4 ½ months, but at least four times each calendar year
2	15 months, but at least once each calendar year	4 ½ months, but at least four times each calendar year
3	7 ½ months, but at least twice each calendar year	2 ½ months, but at least six times each calendar year
4	4 ½ months, but at least four times each calendar year	2 ½ months, but at least six times each calendar year

All gas transmission operators are also subject to the current section 192.613(c) requirements and may conduct additional patrols after a 192.613(c) inspection. These regulations require operators to inspect potentially affected pipeline facilities after an extreme weather event or natural disaster.[63] An operator must commence the inspection within 72 hours after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the personnel and equipment are available.[64]

H. Leak Grading and Repair

1. Leak or Hazardous Leak

a. PHMSA's proposed definition of a leak is overbroad and inconsistent with section 113 of the PIPES Act of 2020.

PHMSA proposes to define both leaks and hazardous leaks as "any release of gas from a pipeline that is uncontrolled at the time of discovery and is an existing, probable, or future hazard to persons, property, or the environment, or any uncontrolled release of gas from a pipeline that is or can be discovered using equipment, sight, sound, smell or touch."[65] The agency proposes to treat all leaks as hazardous and apply this new definition across all Part 192 subparts with the exception of the underground natural gas storage requirements (section 192.12) and the integrity management requirements (subpart O and P).

All leaks are not hazardous. Treating all leaks as hazardous dilutes the importance of a prompt response when there is an immediate risk to life or property. Congress clearly acknowledged the existence of <u>non-hazardous</u> leaks in section 113 of the PIPES Act. Congress directed PHMSA to focus its leak detection and repair programs on leaks that are "hazardous to human safety or the environment" or "have the *potential* to become explosive or otherwise hazardous to human safety."[66] Congress also recognized that some "leaks [are] so small that [they] pose no potential

[63] 49 C.F.R. § 192.613(c).
[64] 49 C.F.R. § 192.613(c).
[65] Proposed 192.3.
[66] 49 U.S.C. § 60102(q)(2)(B)(i)-(ii).

hazard" and therefore do not need to be repaired.[67] PHMSA's proposal to treat all leaks as hazardous is not consistent with this mandate.

b. PHMSA's proposed definition of a leak is also contrary to the Agency's well-developed position on hazardous leaks.

The agency asserts in the NPRM that its regulations have lacked "meaningful guidance regarding which leaks are hazardous".[68] This is incorrect. Since 2009, PHMSA has defined a "hazardous leak" as "a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous."[69] While this definition is not a requirement for transmission operators, many operators have voluntarily incorporated this definition into their procedures. PHMSA has also encouraged gas transmission operators to use this definition.[70] The agency included a definition of leaks in the annual report instructions ("unintentional escapes of gas from the pipeline that are not reportable as incidents under section 192.3.") and for years, applied it to transmission operators.[71] The agency has consistently stated in guidance starting in 1972 that while hazardous leaks must be repaired promptly, the decision as to which leaks are hazardous, depends on the nature of the operation and local conditions.[72] The agency has acknowledged that the "nature and size of the leak, its location, and the danger to the public are among factors that must be considered by the operator"[73]

PHMSA also failed to consider the impact that the conflation of these two definitions would have on the tracking and trending of leak data by individual operators and across the industry. Any change to definitions in Part 191 or section 192.3 must be mirrored in the instructions for §§ 191.11 and 191.17 annual reports.

c. Recommended Definition of a Leak

INGAA supports the Joint Trades' definition of a leak:

> Leak means any uncontrolled release of gas from a pipeline that is designed to transport, deliver, or store gas.

[67] The congressional mandate for advanced leak detection technologies requires a schedule for repairing each leaking pipe "***except a pipe with a leak so small that it poses no potential hazard…***" 49 U.S.C. § 60102(q)(3)(A)(iii)(emphasis added).
[68] 88 Fed. Reg.at 31,916.
[69] 49 C.F.R. § 192.1001; Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines, 74 Fed. Reg. 63,906, 63,934 (Dec. 4, 2009).
[70] PHMSA acknowledged in its Operations and Maintenance enforcement guidance that "while this definition is only applicable to distribution systems, it may provide guidance for defining hazardous leaks." Operations and Maintenance Enforcement Guidance, at 92.
[71] Instructions for Form PHMSA F-7100.2-1 at 14.
[72] PHMSA Letter of Interpretation, PI-72-0109 (Aug. 4, 1972). This interpretation is also cited in the agency's PHMSA Operations and Maintenance Enforcement Guidance which has been in effect since 2010. *See* Operations and Maintenance Enforcement Guidance, at 92.
[73] *Id.*

d. **Releases from relief devices and emergency shutdown devices are controlled and are not leaks.**

It is important to note that releases from relief devices and emergency shutdown devices are controlled and therefore should not be considered a leak. Operators are required under the pipeline safety regulations to design certain pipeline components to release gas in a controlled manner without hazard.[74] The agency states in the preamble that "unintended releases through intended release pathways" are leaks.[75] PHMSA also specifically references releases from relief devices and emergency shutdown devices as leaks.[76] This is not correct. If PHMSA now intends to change its position that all gas releases are hazardous and uncontrolled, then an operator's ability to comply with these design requirements will be impacted.

e. **PHMSA should remove the reference to 'touch' to identify a leak.**

INGAA requests that PHMSA not refer to the unsafe practice of identifying leaks by touch. Placing a digit or a portion of the hand in the path of a leak is dangerous and is not a practice that operators use or condone.

2. **Grading**

a. **Grading Requirements**

Using its definition of a leak, INGAA encourages a distinction in the grading requirements between existing or probable hazards to public safety (grade 1) and probable future hazards to public safety (grade 2).

- A grade 1 leak includes a leak with any of the following characteristics:
  (i) A hazardous leak, as defined in § 192.3.
  (ii) Any amount of escaping gas has ignited;
  (iii) Any indication that gas has migrated into a building, under a building, or into a tunnel;
  (iv) For an underground leak, any reading of gas at the outside wall of a building, or areas where gas could migrate to an outside wall of a building;
  (v) Any reading of 80% or greater of the LEL (60% for LPG systems) in a confined space;
  (vi) 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

- A grade 2 leak includes any leak (other than a grade 1 leak) with any of the following characteristics:

[74] *See* 49 C.F.R. §§ 192.167, 192.169, 192.179, and 192.199.
[75] 88 Fed. Reg. at 31,955.
[76] *Id.*

(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;
Is of sufficient magnitude to pose significant potential harm to the environment, applying one of the following criteria as determined by the operator:

(A) estimated leakage rate of 10 cubic feet per hour (CFH) or more, as indicated by suitable technology; or
(B) estimated ''leak extent'' (land area affected by gas migration) of 2,000 square feet or greater; or
(C) an alternative method for determining environmental significance of a leak.

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

- Grade 3 Leak – Any leak that does not meet the grade 1 or 2 criteria.

i. The agency's proposal for grading is confusing and there are inconsistencies between the NPRM and the PRIA.

In the NPRM, PHMSA proposes that Grade 1 leaks are "an existing or probable hazard to persons and property or a ***grave*** hazard to the environment."[77] PHMSA explains in the preamble that a Grade 1 leak is "a release of gas involving a risk of ignition that is sufficient to be an existing or probable future hazard to public safety, or release of sufficient volume that poses a grave hazard to the environment."[78] In the PRIA, PHMSA states that Grade 1 leaks are "existing or probable hazards to persons or property, or existing hazards to the environment" without any reference to 'grave'.[79] It is not clear if PHMSA assessed the cost and benefits of its new Grade 1 proposal using the definition in the NPRM or the PRIA.

The description of Grade 2 leaks is also confusing. In the NPRM, the agency provides that a Grade 2 leak is "a probable future hazard to persons or property or a *significant* hazard to the environment."[80] However, in the PRIA, PHMSA provides that a Grade 2 leak represents "a probable future hazard to safety or the environment" with no reference to 'significant'.[81] It is also

[77] 88 Fed. Reg. at 31, 975 (emphasis added).
[78] 88 Fed. Reg, at 31,940.
[79] PRIA, at 12.
[80] 88 Fed. Reg. at 31,976 (Proposed section 192.760(c)(1))(emphasis added).
[81] PRIA, at 12.

not clear if the assessment conducted for purposes of the PRIA weighed the costs and benefits of the NPRM definition or the language listed in the PRIA.

The proposed rule also requires that a Grade 2 leak in Class 3 or 4 must be remediated within 30 days. If, in the operator's judgment, a Grade 2 leak is a safety concern, it would be remediated as a Grade 1, and if it is not a safety concern, it would be remediated as all other Grade 2 leaks.

ii. PHMSA should allow gas transmission operators to classify certain leaks as Grade 3.

PHMSA's proposed section 192.760 prohibits gas transmission operators from using the Grade 3 leak classification. In proposed section 192.760(c)(1)(iv), the agency states that a Grade 2 leak includes "*any* reading of gas that does not qualify as a grade 1 leak that occurs *on a transmission pipeline or Type A or Type C regulated gas gathering line*."[82] This language in effect restricts a gas transmission operator from using the Grade 3 classification. PHMSA does not explain this prohibition and does not appear to evaluate the costs of such a prohibition. PHMSA's position is also inconsistent with the GPTC requirements. By not allowing transmission operators to utilize a grade 3 would result in customer impacts and unnecessary blowdowns to fix small but less impactful releases. The Grade 3 classification should be available for all leaks that fit the detailed scoping requirements in proposed section 192.760(c)(1)(i)-v), regardless of the type of pipeline involved.

iii. PHMSA has not evaluated the costs of requiring gas transmission operators to fix all leaks with six months.

Given the lack of authority to use the Grade 3 classification, transmission operators must fix all leaks within six months, if not sooner. The agency has not evaluated the costs of this timeframe. The agency needs to revise its regulatory impact analysis to evaluate the costs of this proposed standard. Operators could reduce emissions by combining certain leak repair projects. Allowing a grade 3 classification would assist operators to properly plan and mitigate emissions.

iv. For leaks that existed prior to the final rule in this proceeding, PHMSA should allow operators one year from the effective date of the rule, not the publication date to complete repairs.

In proposed section 192.760(c)(6), PHMSA provides that "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 publication date of the final rule]."[83] The deadline to complete these repairs should be one year from the effective date of the final rule, not the publication date.

[82] Proposed section 192.760(c)(1)(iv)(emphasis added).
[83] Proposed section 192.760(c)(6).

3. Repairs

PHMSA should extend the proposed repair deadline of 6 months for certain Grade 2 leaks (not in a HCA, Class 3, or 4 location) to one year. The agency proposes that Grade 2 leaks, not in a HCA, class 3 or 4 location, must be repaired within six months of detection unless a shorter deadline exists in an operator's integrity management procedure. INGAA proposes that this deadline should be extended to 1 year. A one-year deadline would allow operators to more efficiently conduct work in the field by bundling projects at nearby locations. INGAA is also concerned with the agency's estimate of costs to repair a leak and has addressed that topic in Exhibit A.

I. Advanced Leak Detection Program

PHMSA proposes that operators must develop an Advanced Leak Detection Program (ALDP), a comprehensive set of procedures and technologies to detect all leaks.[84] The ALDP must specify the leak detection equipment the operator will use,[85] leakage survey frequencies,[86] and the prescribed performance standard.[87] All leakage surveys conducted in accordance with section 192.706 must use the leak detection equipment listed in the ALDP and that equipment must meet a sensitivity of 5 parts per million (5 ppm) when measured from a distance of 5 feet, regardless of the type or location of pipeline.[88]

These proposals are not feasible for transmission operators, are inconsistent with EPA requirements, and go beyond the statutory mandate in the PIPES Act.

1. Minimum Sensitivity of 5 ppm

a. The 5 ppm detection sensitivity is not feasible for transmission pipelines.

Congress directed PHMSA to establish minimum performance standards that "reflect the capabilities of commercially available advanced technologies," and "are appropriate for the type of pipeline, the location of the pipeline, the material of which the pipeline is constructed, and the materials transported by the pipeline."[89] PHMSA has not evaluated the commercial availability of advanced technologies with a sensitivity of 5 ppm and it has not determined specific performance standards for each type of pipeline. Instead, the agency has proposed a single performance standard applicable to all pipelines and all leaks, regardless of the type of pipeline or location. Technology with this detection sensitivity is not feasible for transmission pipelines and the market cannot currently provide widespread availability of it.

The technology to identify leaks on buried pipe at the proposed 5 ppm standard at a distance of 5 feet has not been demonstrated across the range of situations that exist on transmission systems.

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[84] 88 Fed. Reg at 31,962.
[85] Proposed section 192.763(a)(1).
[86] Proposed section 192.706.
[87] Proposed section 192.763(b).
[88] 88 Fed. Reg at 31,959; *See also*, proposed section 192.763(b).
[89] 49 U.S.C. § 60102(q)(2)(A)(i)-(iv).

While this threshold might be appropriate for distribution utility assets, it is not a useful measure for linear infrastructure such as transmission pipelines. Parts per million is a point source unit of measurement that provides how much gas is present at a specific location. It is not useful when attempting to measure a concentration of gas remotely or over a large area at one time. The agency must select a feasible detection sensitivity performance standard for gas transmission operators to employ. Otherwise, all gas transmission operators will be forced to file section 192.18 notifications when the final rule becomes effective. A more useful approach for transmission operators would involve remote sensing technologies that measure a gas plume, rather than a point source, can be used from the air, and not at a distance of 5 feet.

b. The 5 ppm sensitivity is not consistent with EPA requirements.

EPA defines a leak from a "fugitive emission component" (i.e., valve, connector, pressure relief device, open-ended line, flange, cover, and closed vent system) at a compressor station as "an instrument reading of 500 parts per million (ppm) or greater" using EPA's reference method for instrument LDAR monitoring.[90] Leaks from equipment within process units at onshore natural gas process plants are defined differently and range from 500 to 10,000 ppm.[91] 500 ppm represents 1% of the lower explosive limit of methane gas.

PHMSA stated that it chose 5 ppm because it is a "protective threshold of detection sensitivity" compared to EPA's standard of 500 ppm.[92] PHMSA provided no technical basis for the 0.01% threshold and it is not clear why PHMSA chose the threshold. Congress directed PHMSA "to conduct leak detection and repair programs . . . to protect the environment."[93] EPA's most stringent regulatory definition of a leak is two orders of magnitude higher than PHMSA's proposed minimum sensitivity. PHMSA's proposal exceeds the statutory mandate, and would impose significant burdens on pipeline operators with little to no associated environmental benefit.

c. The 5 ppm sensitivity, as applied to transmission, will result in numerous false positives.

When selecting a performance standard for the leak detection of transmission pipelines, the agency should account for the fact that too restrictive of a performance standard may lead to numerous false positives. The agency has not accounted for the resources that are typically spent on responding to indications of a leak to determine if it is truly a natural gas leak or alternatively, decayed matter from natural sources. One of INGAA's members deployed the 5 ppm concentration level for certain areas of its pipeline system. It found 39 leaks but upon further investigation, the company determined that 36 were false. Operators will need to extend resources to investigate each and every leak and PHMSA should acknowledge that too restrictive of a performance standard is not beneficial.

[90] 40 CFR § 60.5397a(a)(1).
[91] 40 CFR §§ 60.482-2a-60.482-11a.
[92] 88 Fed. Reg. at 31,933. PHMSA also acknowledged that EPA's 500 ppm standard is "1% of the lower explosive limit of methane gas" which calls into question why 5 ppm is necessary to be a protective threshold.
[93] 49 U.S.C. § 60102(q)(1)(B).

d. Instead of applying a 5 ppm detection performance standard for all leakage surveys irrespective of the type or location of the pipeline, the agency should appropriately tailor requirements to specific infrastructure.

Transmission operators typically rely on aerial leakage surveys and may need to use existing remote sensing technology to achieve PHMSA's proposed ALDP requirements. This type of technology has not matured to meet a 5 ppm sensitivity standard. Requiring a 500 ppm or equivalent standard for aerial patrol would be feasible and practical and would also be consistent with EPA's requirements. With an appropriate effective date of PHMSA's final rule to allow advanced technology providers to ramp up operations and operators to develop procedures, train personnel, and acquire equipment, a 500 ppm would present an achievable standard.

PHMSA should allow operators to use EPA-approved technologies and corresponding sensitivity levels. EPA and state programs have robust requirements to regulate methane leaks in areas within the fence line. As PHMSA acknowledges in the NPRM, EPA requires the "repair of all leaks visible with an OGI [optical gas imaging] device or that produce an instrument reading of 500 ppm or greater."[94] PHMSA also confirms that "OGI cameras…are commonly used for fugitive emissions monitoring at LNG plants, compressor stations, and other facilities."[95] However, PHMSA proposes to require leakage surveys on valves, flanges, pipeline tie-ins, and ILI launcher and receiver facilities using the equipment that can meet a minimum sensitivity of 5 ppm.[96] This sensitivity requirement would preclude the use of OGI cameras. PHMSA should capitalize on the benefit of existing EPA regulations and allow operators to use OGI devices or an equivalent for a consistent and efficient regulatory program.

As outlined in the Joint Trades' comments, INGAA supports a multi-tiered approach for establishing minimum sensitivity of leak detection equipment in § 192.763(a)(1)(ii).

Unless using non-optical continuous monitoring system (e.g., acoustical or pressure monitoring systems), and soap solution, leak detection equipment used for leakage surveys must have a minimum sensitivity capability of one of the following:

- 5 parts per million for subsurface piping leakage surveys using handheld leak detection equipment, unless described in § 192.763(a)(1)(ii)(C);
- 500 parts per million (or 10 kg/hr mass flow equivalent) for each gas being surveyed using infrared, or laser-based leak detection equipment; mobile, aerial, or satellite-based platforms; or using fixed continuous monitoring sensors within buildings;
- 500 parts per million for handheld leak detection equipment for gases being surveyed within buildings or

[94] 88 Fed. Reg, at 31,932.
[95] 88 Fed. Reg, at 31,933.
[96] Proposed section 192.763(a)(1)(iii)(A)-C).

- sensitivity otherwise meeting the requirements of 40 C.F.R. Part 60, subpart OOOO for optical gas imaging or equivalent

INGAA proposes the following regulatory text for clarity purposes:

§ 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 identify operator approved leak detection equipment used to perform leakage surveys and other leak detection activities.

(ii) Unless using non-optical continuous monitoring system (e.g., acoustical or pressure monitoring systems), and soap solution, leak detection equipment used for leakage surveys must have a minimum sensitivity capability of one of the following:

(A) 5 parts per million for subsurface piping leakage surveys using handheld leak detection equipment, unless described in § 192.763(a)(1)(ii)(C);

(B) 500 parts per million (or 10 kg/hr mass flow equivalent) for each gas being surveyed using infrared, or laser-based leak detection equipment; mobile, aerial, or satellite-based platforms; or using fixed continuous monitoring sensors within buildings;

(C) 500 parts per million for handheld leak detection equipment for gases being surveyed within buildings or

(D) sensitivity otherwise meeting the requirements of 40 C.F.R. Part 60, subpart OOOO for optical gas imaging or equivalent

Before using this equipment in a leakage survey, the operator must validate the sensitivity at which the survey is to be tested in accordance with the manufacturer's instructions.

(iii) Records validating that the ALDP equipment meets the minimum sensitivity requirements must be maintained for at least 5 years after the date that equipment is no longer used by the operator.

2. **PHMSA should provide a three-year compliance date for the Advanced Leak Detection Program requirements to allow for the availability of leak detection technology.**

The agency proposes that all of these new requirements would become effective six months after the publication of a Final Rule. This is not feasible, reasonable, or practicable. As discussed in these comments, PHMSA should adopt a three year effective date of the Final Rule to allow for the technology to be available on a widespread basis and for operators to create new procedures, acquire necessary equipment, develop procedures, and train personnel. If PHMSA chooses not to extend the proposed effective date of the rule, at a minimum, PHMSA should provide a three year compliance date for the ALDP requirements.

J. Mitigating Vented and Other Emissions from Gas Pipeline and Facilities

PHMSA proposes that when an operator conducts any intentional release of gas, including blowdowns or venting for scheduled repairs, construction, maintenance, and operations tasks, it must reduce the release of gas to the environment through one of six proposed methods. Those methods include (1) isolating the smallest section of the pipeline needed to complete the task; (2) routing gas from the nearest isolation valve or control fitting to a flare as fuel gas; (3) reduce the pressure by using in-line compression; (4) reduce the pressure by using mobile compression; (5) transfer the gas to a segment of a lower pressure pipeline system adjacent to the nearest isolation valve; or (6) employ an alternative method which will result in a release volume reduction of at least 50% compared to venting gas directly to the atmosphere.[97]

1. PHMSA should expand the exception for emergencies to include safety risk and commercial impacts.

The agency has proposed one exception to the provisions in proposed section 192.770(a)(1)-(6). PHMSA limits the exception to emergencies.[98] There are several potential events where an operator might be faced with a safety risk to its personnel, contractor, or landowners and need to vent the gas immediately. PHMSA should also consider situations where a pipeline is the only source of gas for a community and whether waiting for mobile compression equipment is the appropriate response rather than venting the gas to perform the necessary maintenance. INGAA recommends expanding the proposed exception to include safety risks in the judgment of the operator and potential commercial impacts.

2. PHMSA should not restrict the use of flaring.

In the NPRM, PHMSA proposes to restrict the use of flaring. Flaring can reduce the effect of emissions on climate change by up to 25 times. If operators were to flare instead of venting, with 95% flare efficiency, the industry would reduce the GWP of the emission by almost 91%. Considering PHMSA proposes in section 192.770 to accept a 50% reduction in the vent volume

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[97] 88 Fed. Reg. at 31,978.
[98] Proposed section 192.770(b).

as a sufficient threshold for an emission reduction method, flaring should still be acceptable as a primary method to reduce the emissions. Restricting the use of flaring to instances where other measures are impracticable will cause a higher cost to operators and may actually cause more harm than good to the environment.

3. Operators will need more time than six months to make preparations for compliance with section 192.770.

PHMSA proposes a six-month effective date for the final rule in this proceeding. As discussed in this comment document, INGAA requests a more realistic effective date of three years. This longer effective date is particularly important to assist operators with complying with proposed section 192.770. The natural gas industry will require additional time to evaluate applicable control measures to mitigate or reduce methane emissions on transmission pipelines using the proposed techniques. For example, operators will need to address the following considerations prior to purchase or rental of temporary compression units: mechanical capability, infrastructure siting, air compressor or compressor power, liquids management, equipment and hose maintenance, fleet size - unit per yard, rental availability, transportability, flexibility, smaller diameter piping, runtime, downtime, efficiency, flow capacity, system planning integration and standardization of tracking volume estimates. For flaring, operators will need to assess: siting infrastructure, transportability, adjustable height, trailer tag, hydrocarbon destruction percentage, state and federal environmental requirements.

The agency is expecting operators to have mobile compression on standby when each operator conducts operations, maintenance, and repair activities that require an intentional release of gas. This is not realistic or practical. Many transmission ROWs are in remote locations and there can be a delay to secure mobile compression at the scene. INGAA is also concerned that the mobile compression companies are not ready to accommodate the significant increase in demand and will need more time to ramp up operations.

Finally, operators will need to evaluate upcoming projects so that some projects located in close proximity can be conducted on the same timeline leading to improved efficiencies and increased reductions in methane.

K. Underground Natural Gas Storage Facilities

1. PHMSA should not apply subpart N operator qualification requirements to underground natural gas storage facilities (UNGSFs).

The NPRM solicits comment on whether to apply certain subpart N operator qualification requirements to underground natural gas storage facilities (UNGSFs).[99] Apart from recognizing that PHMSA does not currently apply subpart N to UNGSFs, the NPRM provided no further discussion on the topic, and did not identify any reason for doing so. Without any detail in the NPRM, the Associations cannot substantively respond to the request. However, the Associations note that PHMSA has long understood that UNGSFs are unique facilities that should be treated

[99] 88 Fed. Reg. 31,890, 31,945 (May 18, 2023).

differently than other regulated pipeline facilities.[100] Sec. 192.12 explicitly exempts UNGSFs from other part 192 requirements, including subpart N. Further, API RPs 1170 and 1171 already include sufficient qualification and training requirements that are tailored to UNGSFs. Adding subpart N requirements may cause issues with existing 1170 and 1171 requirements and the new requirements may be incongruent with UNGSF operations.

2. PHMSA should not introduce leakage survey frequency and leak detection equipment requirements for UNGSFs without providing a detailed proposal.

The NPRM seeks comment on whether to amend Sec. 192.12 to apply leakage survey frequency and leak detection equipment requirements to UNGSFs.[101] PHMSA did not provide any details as to what these requirements might look like or conduct a cost-benefit analysis to support applying these requirements to UNGSFs. The NPRM and preliminary regulatory impact assessment fail to provide the necessary analysis to support the inclusion of UNGSF leakage survey or leak detection equipment requirements in the final rule.

IV. Conclusion

INGAA supports PHMSA's efforts to prescribe gas pipeline leak detection and repair regulations consistent with the mandate in section 113 of the PIPES Act. INGAA urges the agency to modify its proposals as discussed in these comments and reevaluate the costs and benefits associated with the NPRM.

[100] *See* PHMSA UNGSF FAQs, No. 12, which states subpart N does not apply to UNGSFs and operators should use the provisions in API RPs 1170 and 1171 for training and qualifications.
[101] 88 Fed. Reg. 31,890, 31,926 (May 18,2023).

<u>Exhibit A</u>

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY

Pipeline Safety: Gas Pipeline Leak	)	
Detection and Repair	)	Docket No. PHMSA-2021-0039

Comments of the Interstate Natural Gas Association of America on the Preliminary Regulatory Impact Analysis for Gas Transmission Pipelines

The Interstate Natural Gas Association of America (INGAA) submits the following analysis of the Preliminary Regulatory Impact Analysis (PRIA)[1], which assesses the costs and benefits of PHMSA's Gas Pipeline Leak Detection and Repair Proposed Rule (the Proposed Rule).

I. Executive Summary

On May 18, 2023, the Pipeline and Hazardous Materials Safety Administration (PHMSA or the Agency) published a proposed rule in the Federal Register to Docket No. PHMSA-2021-0039, including a supporting PRIA containing benefits and costs of the proposed rule.[2] INGAA has reviewed the PRIA and found substantial flaws. The costs of the related compliance activities are understated, and the benefits of the proposed rule are overstated. Table 1 summarizes the significant differences between PHMSA and INGAA costs and calculates the total cost per metric ton of methane. Of note, the average emission reduction in Table 33 of the PRIA shows the annual incremental emission reductions by year, which averages to a reduction of 627 metric tons of methane emissions annually.[3] PHMSA failed to conduct a cost effectiveness evaluation to determine the cost per metric ton of methane reduction. As such, Table 1 represents INGAA's calculation of the data that PHMSA presented and the recalculated INGAA costs using more precise data.

[1] PHMSA, Preliminary Regulatory Impact Analysis, Docket No. PHMSA-2021-0039 (April 2023), *hereinafter, "*the PRIA", https://www.regulations.gov/document/PHMSA-2021-0039-0019.
[2] https://www.regulations.gov/document/PHMSA-2021-0039-0019
[3] PRIA, at 74.

Table 1: Comparison of Costs, Emission Reductions and Cost Effectiveness

Transmission Costs: (3% discount, $M)		PHMSA annualized	INGAA annualized
	Patrols	--	$93-$372
	Leakage Surveys	$12.2	$128
	Leak Repair	$1.5	$5.9-$14.5
	Other Reporting	$1.2	$1.2
	Total	**$14.9**	**$228-$516**
Emission Reductions (metric tons CH4)	Average Emission Reductions [PHMSA average annual, less inventory of emissions][4]	-627	-627
Cost Effectiveness ($/metric ton CH4)	**Annual Cost Effectiveness**	**$23,763**	**Low: $363,636** **High: $822,967**

As such, INGAA submits the following comments and recalculations to illustrate the following:

The cost effectiveness of the proposed requirements is unreasonable. To reduce one metric ton of methane will cost the gas transmission industry between $363,636 to $822,967, which is exponentially higher than the EPA's reasonableness upper-bound threshold of $1,970/metric ton of methane. Even assuming that PHMSA cost/benefit calculations are accurate, which they are not, PHMSA's $23,763 cost per ton of methane is more than 10 times what the EPA—the lead federal environmental regulator—has deemed reasonable. There is a significant delta between EPA's and PHMSA's $/ton of methane reduction values. PHMSA should demonstrate how its NPRM is cost effective supported by the PRIA.

- Leak rates will fundamentally fall, not increase, as other regulations, such as RIN 2137-AF39 (commonly referred to as PHMSA RIN 2) take effect. Throughout the PRIA, the leak rate of 0.046 per mile stays constant and does not account for the impact and reduction of leaks. Instead, PHMSA assumes the number of leaks will increase each year based on the continual growth of gas transmission mileage. In fact, PHMSA asserts that more than 38,000 miles of new pipeline will be constructed over the 15-year period between 2024-2038. This is not accurate according to federal government data. PHMSA should explain the dramatic increase in mileage of over 2,500 miles each year, while an average annual increase of 349 transmission miles is supported in Table 2 of the PRIA based on the six-year period through 2020.[5] According to PHMSA data, overall transmission mileage has remained relatively flat and has not significantly increased

[4] PRIA, at 74.
[5] PRIA, at 22.

since 2015.[6] Furthermore, according to the U.S. Energy Information Administration (EIA) gas transmission pipeline new construction has dramatically decreased since 2018.[7]

- PHMSA cost calculations are magnitudes lower than will be absorbed by the gas transmission industry. INGAA recalculated these costs to demonstrate that costs will range between $228 to $516 million annually, not $14.9 million per year as the agency asserts.

- PHMSA benefits, specifically the emission reductions calculated as part of the proposed rule are higher than the true emission reductions calculated in the PRIA. This is due to a number of factors, including the addition of inventoried emissions of approximately 1190 metric tons of methane even before the rule goes into effect, an inaccurate leak per mile-year of 2.4 MT and overall flawed emission modeling approach.

- The proposed rule will result in small emission reductions and detract from resources that could be used for higher emission voluntary practices, such as pumping down to lower pressures during blowdown events. Most leaks that would be repaired will be small and costly and may cause more methane emissions to repair in the proposed time frame than saved (192.760).

II. Overview of Cost/Benefit Comments

The costs attributable to the proposed rule as outlined in the PRIA are based on the incremental cost of conducting more frequent leak patrols, using advanced leak detection equipment, and conducting timely repairs.

The calculations contained in the PRIA and the assumptions that were developed relative to the major compliance categories fail to fully evaluate the consequences of the proposed regulatory action. INGAA has recalculated the costs based on current regulatory requirements (baseline) versus the cost of implementing the new provisions (incremental)— related explicitly to leak patrol, leak survey and leak repair. In its calculations, INGAA has used PHMSA's data for illustrative purposes or made assumptions to demonstrate the flaws in PHMSA's analysis. It is important to note that INGAA does not agree with all of PHMSA's data and, in many cases questions the accuracy of the data given the small sample size from which PHMSA pulled the data and other issues with the data noted below. Additionally, INGAA identified mileage inaccuracies that substantially change and understate the total cost.

[6] https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems
[7] https://www.eia.gov/todayinenergy/detail.php?id=55699

a. The agency has failed to conduct an adequate cost assessment of these proposed requirements.

The Agency has estimated natural gas transmission costs based on dated rate cases involving a single operator that represents only two percent of total transmission mileage in the U.S. While these unit costs are not representative of industry, INGAA is even more concerned that the cost impacts are underestimated due to a combination of incorrect assumptions about current practices, the lack of a regulatory baseline, and inaccurate mileage estimates that do not reflect all the applicable provisions within the NPRM.

Congress requires the Agency to conduct a risk assessment for each pipeline safety standard proposed under 49 U.S.C. § 60102. 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.[8]

The Office of Management and Budget (OMB) directs executive agencies in its Circular A-4 (2003) to identify a baseline when evaluating the benefits and costs of a proposed regulation and its alternatives.[9] OMB defines the baseline as "what the world will be like if the proposed rule is not adopted"[10] and then the agency compares the cost of that approach with its proposal.[11] Incremental costs are then defined as the "difference between a proposed action's costs and the benefits and the baseline."[12] Numerous federal courts have accepted the baseline approach.[13]

OMB's guidance provides for ways to develop baseline measures to calculate appropriate benefits and costs. The circular specifies what constitutes an appropriate baseline including the

[8] 49 U.S.C. § 60102(b)(3)(A)–(D).
[9] OMB Circular A-4.
[10] Circular A-4 at 15, United States Office of Management and Budget (Sept. 17, 2003), https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf
[11] *Cape Hatteras Access Pres. All. v. U.S. Dep't of Interior*, 344 F. Supp. 2d 108, 130 (D.D.C. 2004).
[12] *Northern New Mexico Stockman's Ass'n v. U.S. Fish and Wildlife Service*, 494 F.Supp. 3d 850 (D.N.M. 2020) (citing OMB Circular A-4 at 16), *aff'd* 40 F.4th 1210 (10th Cir. 2022).
[13] *See Ariz. Cattle Growers' Ass'n v. Salazar*, 606 F.3d 1160, 1173 (9th Cir. 2010); *Fisher v. Salazar*, 656 F. Supp. 2d 1357, 1371 (N.D. Fla. 2009); *Cape Hatteras Access Pres. All. v. U.S. Dep't of Interior*, 344 F. Supp. 2d 108, 130 (D.D.C. 2004).

use of current regulatory programs as a reasonable basis for developing monetary impacts of proposed rulemaking.

The OMB recently released an updated draft circular framework. Once finalized, the proposed update to the circular will supersede the previous version and is likely to be in effect when PHMSA publishes its final leak detection and repair rule. The proposed updated circular contains updates on specific sections, including more explicit language related to choosing an appropriate analytic baseline. The following section outlines the latest draft guidance from OMB related to baseline practices in creating meaningful and transparent baseline costs:

> *An agency's regulation should generally be assessed in a manner that compares against a state of the world that conforms to any relevant previously issued regulations. Attention should also be given to analysis that isolates meaningful changes relative to any sub- regulatory action (e.g., agency guidance) in a supplementary analysis. This dual-baseline approach allows for assessment relative to both a previous regulation and any subsequent guidance. Relatedly, it acknowledges the range of possible future behavior patterns by affected entities, which may not match what is observed at the time the regulatory analysis is conducted.*[14]

PHMSA disregarded this guidance and deemed that all operators currently follow recommended practices contained in the Gas Pipeline Technology Committee (GPTC) "Guide for Gas Transmission, Distribution, and Gathering Piping Systems, Appendix G-192-11", which describes leak classification procedures and criteria for leak survey and grading. Although some operators integrate classification procedures based on this guidance, it is erroneous to assume that all organizations operate their systems based on this process. In fact, the GPTC has about 100 members from gas distribution, gathering and transmission systems, manufacturers, and federal and state regulators, while there are 1,308 total gas gathering and transmission systems across the U.S.[15] Additionally, the proposed rule does not follow the recommendations of GPTC and would increase cost to those that are following the current version of GPTC.

PHMSA's use of an incorrect baseline — and using unreasonable baseline costs to determine cost impacts, including the assumption that most operators employ the GPTC guidance — has a substantial impact on the annualized cost of the proposed rule. The NPRM significantly underestimates the cost of implementing the provisions of the proposed rule and does not follow the requirements of the Pipeline Safety Act nor the current or proposed guidance from OMB. For example, when calculating leak survey costs, PHMSA failed to account for aboveground facility surveys. In general, PHMSA was not transparent on the amount of mileage used in calculations that would be impacted by compliance activity. It would be appropriate to include sufficient data for cost structures to be reproducible. INGAA recommends that PHMSA update the PRIA based on the current regulatory environment as a baseline to calculate incremental costs and update mileage estimates to identify system impacts accurately.

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[14] https://www.whitehouse.gov/wp-content/uploads/2023/04/DraftCircularA-4.pdf
[15] PRIA, at 120.

Table 2 summarizes the total annualized incremental costs calculated by the Agency and compares the findings to recalculations developed by INGAA. The following describes the methodology INGAA used to recalculate the proposed rule:

- Patrol: the annualized patrol costs are based on mileage estimates contained in the PRIA in Table 3 multiplied by the incremental frequency of patrols by class (11 additional patrols in Class 1 and 2, 10 additional patrols in Class 3, and 8 additional patrols in Class 4) and multiplied by the PHMSA costs of $32 to $128 per mile as described in the PRIA.[16] PHMSA's zero cost basis for this provision is based on the baseline assumption that all operators perform patrols of their entire system at least once a month, instead of using the current regulatory requirements as a baseline.

- Leak Survey: survey costs are based on estimating the amount of HCA, leak-prone pipe and the number of aboveground surveys that would be required under the proposed rule in Class 1 and 2 Locations. This mileage was multiplied by the additional leak survey frequency and the cost of ALD published in the PRIA of $515 per mile. To account for the incremental cost of the survey, INGAA multiplied the total mileage by class frequencies with an incremental cost of $387 per mile. PHMSA's annualized $12.2 million calculation fails to include the additional provisions of surveying aboveground facilities and the incremental cost of performing all leak surveys using ALD methods.

- Leak Repair: costs associated with leak repair are based on a four-step process. *Step 1* involves calculating the number of positive and false positive leaks that will be detected based on a lower-bound rate of 0.0067 and a higher-bound rate of 0.078 detections per mile rate and the cost to investigate each leak indication assumes 6 hours of a technician's time at a fully loaded labor rate of $72.61 per hour. *Step 2* uses the PHMSA ALD leak rate to calculate the incremental leaks compared to baseline practices and multiplies by the cost to perform a metallurgical investigation. *Step 3* includes the actual repair of the leak, which assumes a percentage of leaks incur low, medium, and high costs. *Step 4* contains costs for performing the post-repair confirmation for each leak using a labor rate of $72.61. For comparison, PHMSA did not accurately calculate the cost of investigation of potential leaks, proper investigation of each leak as described in the NPRM, the range of repair costs or accurate labor rates throughout section 4.1.3 of the PRIA.

[16] PRIA, at 37.

Table 2: Total Annualized Costs by PHMSA vs. INGAA (M$, 3 percent discount rate)

Transmission	Requirements	PHMSA annualized costs	INGAA annualized costs
	Patrols	--	$93-$372
	Leakage Surveys	$12.2	$128
	Leak Repair	$1.5	$5.9-$14.5
	Other Reporting	$1.2	$1.2
	Total	$14.9	$228-$516

Sections III, IV, and V below provide a more realistic cost estimate for the major compliance areas contained in the NPRM.

b. The agency has failed to conduct an adequate benefit assessment of these proposed requirements.

The PRIA includes a section on quantifying the environmental benefits of the proposed rule with the assumption that improving the leak detection program and accelerating repairs will result in avoided gas loss and avoided methane emissions.[17] The annual changes to methane emissions are estimated in Table 33 of the PRIA and range from a reduction of -1,300 to -10,100 metric tons of CH_4 annually.[18] PHMSA's calculation includes approximately 1190 MT of CH_4 of inventoried annual emissions from transmission leaks before 2024 when the rule goes into effect. Including an inventory of emissions should not be part of the reduction emission calculation.

Based on PHMSA's evaluation, the compliance activities of the NPRM result in an annual emission reduction of an average of 627 MT of methane. This is based on PHMSA's projection of incremental leaks multiplied by a 2.4 MT of CH_4 per leak-year factor. PHMSA explains their methodology by using the EPA emission factors for gas transmission of 10.9 kg/mile, which translates to a value of 2.4 metric tons of CH_4/leak-year (10.9 kg/mile x 308,972 mileage/1000/baseline leaks). Although the EPA 10.9 kg/mile parameter is widely used, it is worth noting that this value is based on GRI/EPA 1996 data sources, which are outdated and not reflective of changes to pipeline systems over the past two decades such as voluntary methane reduction programs, leak detection technology advancements and other state and federal requirements. Two countervailing points illustrate the error of using the 2.4 MT methane per leak calculation. First, the outdated EPA emission factor for gas transmission is modeled on the average leakage rate for distribution main pipelines which is not indicative of a rate for transmission pipelines.[19] The second point is the assumption that the mileage will increase by over 2500 miles annually and this increase ~~in pipeline mileage~~ results in more leaks over time. In fact, the PRIA supports that mileage increases will be minimal (349 miles annually based on reported mileage changes by class location for calendar years 2015-2020).[20] Further, adding new pipe annually would not be expected to increase leaks. As part of the implementation of RIN

[17] PRIA, at 72.
[18] PRIA, at 74.
[19] https://www.epa.gov/sites/default/files/2016-08/documents/9_underground.pdf, at 38.
[20] PRIA, at 22.

2137-AF39, requirements such as 192.319 and 192.461 are being implemented to prevent external corrosion, one of the noted factors for causing leaks. Requirements on existing pipelines such as, 192.465 and 192.473 are also expected to reduce external corrosion. PHMSA has expanded the requirement to assess pipelines outside of HCAs and to apply a more conservative repair criteria to all pipelines in all class locations. In addition, 192.478 was proposed to further reduce internal corrosion. It was PHMSA's expectation that the implementation of RIN2137-AF39 would reduce leaks and ruptures to the industry and thus the justification for the rule.

Further, industry has shown that implementing reoccurring LDAR programs have a diminishing return over time. Results have shown that the first survey identifies and remedies most leaks, resulting in less leaks per year.[21] The PRIA incorrectly assumes that leaks will increase annually when in fact the annual emission reductions will be less over time. PHMSA needs to revise its regulatory impact analysis to accurately account for all of these factors.

Without taking these considerations into account, the PRIA specifies a reduction of methane emission of approximately 627 metric tons of methane for gas transmission annually.[22] Table 3 shows the annual methane reductions by year.

Table 3: Annual Methane Emissions (metric tons CH4)

Year	Mileage	Incremental Leak	2.4 MT Per Leak
2024	308972.6	246	590.3
2025	311489.8	248	595.1
2026	314007	250	600.0
2027	316746	252	605.2
2028	319485	254	610.4
2029	322224	257	615.7
2030	324963	259	620.9
2031	327702	261	626.1
2032	330570	263	631.6
2033	333438	265	637.1
2034	336306	268	642.6
2035	339174	270	648.0
2036	342042	272	653.5
2037	344910	275	659.0
2038	347778	277	664.5
		Average Annual	**627**

[21] https://www.api.org/~/media/files/news/letters-comments/2015/15-december/api-comments-on-nsps-12042015.pdf API comments to Docket ID Number EPA-OAR-2015-0216, at 124.
[22] PRIA, at 74.

c. The agency has failed to address the unreasonable cost effectiveness of the rule.

Insofar as the PRIA understates the costs and overstates the benefits of the compliance activities of the proposed rule, the proposed rule does little to address climate change or reduce methane emissions for gas transmission as outlined in *1.1 Determination of Need* section of the PRIA.[23] Specifically, INGAA questions if spending between $228-$516 million annually for a reduction of 627 metric ton of CH4, is a reasonable or appropriate use of resources or meets the statutory and regulatory thresholds for the cost/benefit analysis. To reiterate this point and show the level of unreasonableness, to reduce one metric ton of methane will cost the gas transmission industry between $363,636 to $822,967.

To illustrate this point, INGAA has performed a cost effectiveness evaluation comparing PHMSA's projected costs and emission reductions to INGAA's recalculations to understand the cost per ton of emission reductions. For this analysis, Table 4 shows the total cost effectiveness calculations using the PHMSA emission factors, knowing that PHMSA's 2.4 metric ton of CH4/leak-year is overinflated and multiplying by the incremental leaks identified in the PRIA (also high), and excluding the inventory of emissions.

Table 4: Cost Effectiveness Evaluation Comparison of PRIA and INGAA Recalculations

Transmission	Requirements	PHMSA	INGAA
	Total annualized costs	$14.9	$228-$516
	Average Emission Reductions (metric tons CH4) [average annual, less inventory of emissions]	-627	-627
	Annual Cost Effectiveness ($/metric ton)	$23,763	Low: $363,636 High: $822,967

This analysis demonstrates the magnitude of error in cost effectiveness on a cost per metric ton basis. Furthermore, even using the PHMSA cost per metric ton data shows a greater value than the $1,970/ton that EPA has deemed to be an upper-bound threshold in its proposed methane reduction rulemaking for the oil and gas industry.[24] EPA conducted a Best System Emission Reduction (BSER) analysis in November 2021 in its proposed rule and then again confirmed the analysis in December 2022 in its supplemental rule, which describes the Agency's approach for evaluating control costs on regulatory actions. They concluded that $1,970/ton of methane reduction was reasonable. PHMSA must explain why it should not utilize EPA's upper-bound threshold value of $1,970/ton of methane reduction.

PHMSA's cost effectiveness value is $23,763 per metric ton of methane. By comparison, in 2021 and 2022, EPA established an upper-bound cost effectiveness threshold

[23] PRIA, at 9.
[24] https://www.govinfo.gov/content/pkg/FR-2022-12-06/pdf/2022-24675.pdf, at 74718 Section E.

of $1,970/ton. There is a significant delta between EPA's threshold and PHMSA's cost per ton of methane. PHMSA should explain why they did not perform a cost effectiveness analysis in the PRIA or explain why such a departure in cost effectiveness is warranted. PHMSA should consider defining a cost effectiveness threshold, similar to EPA's cost effectiveness upper-bound threshold, when considering reducing methane emissions. For example, using the upper-bound EPA threshold, we assume that this NPRM would not exceed $1.28 million for gas transmission pipelines using an annual goal of 627 metric tons of methane emission reduction.

INGAA recommends that PHMSA reconsider the costs of the rule and ensure that provisions of the NPRM are cost effective and reasonable by conducting an analysis similar to the EPA BSER process used to establish its upper-bound threshold. Such an analysis, will result in a cost effective rule.

III. Patrol Cost Recalculations

The proposed rule increased the number of patrols on gas transmission systems to 12 times a year. PHMSA assumed that one of the monthly visual patrols would occur at the same time as the annual leak survey, and therefore costs were based on 11 patrols annually. PHMSA estimated the unit cost of patrol between $32 and $128 per mile. [25] PHMSA cited the Pacific Gas and Electric's current patrol program as well as unspecified input from operators to the Agency as evidence that transmission operators currently patrol their pipelines monthly and therefore presumed there is no incremental costs associated with the provisions of increasing leak patrol to monthly. [26]

The Agency acknowledged in the PRIA that some operators may not currently conduct patrols monthly and calculated the impact for *intrastate* pipelines at between $35 million and $140 million per year. PHMSA limited this cost assessment to intrastate operators with arguably shorter pipelines and used a cost of $128 per mile to calculate the total cost. In one section of the PRIA, PHMSA stated that the appropriate cost is $128 per mile but then in other sections of the PRIA, the Agency noted that the unit cost is $218 per mile without explanation.[27]

PHMSA should recalculate the patrol costs following the direction of OMB *Circular A-4* and relevant case law. PHMSA should use the current requirements in section 192.705(b) as the baseline and compare with the proposed rule to produce the incremental cost impact. INGAA has assessed those costs and provides the following data based on mileage by class in Table 5 and PHMSA unit costs of $32 per mile and a high cost of $128 per mile by class and increased frequency outlined in Table 6. These INGAA calculations are based on publicly available PHMSA data in the NPRM, PRIA and on PHMSA's website.

INGAA developed costs based on first developing the mileage impacts by year and class location using the increase in mileage extrapolated through 2038 that was provided by PHMSA in the PRIA. Table 5 contains the mileage by class starting in 2024 and increasing through 2038.

Table 5: Mileage by Class

[25] PRIA, at 37.
[26] PRIA, at 37.
[27] PRIA, at 141.

Year	Class 1 mileage	Class 2 Mileage	Class 3 Mileage	Class 4 Mileage
2024	242,147	31282	34669	875
2025	244,173	31544	34896	877
2026	246,199	31806	35123	879
2027	248,416	32084	35365	881
2028	250,632	32362	35607	883
2029	252,849	32640	35850	886
2030	255,065	32918	36092	888
2031	257,282	33196	36334	890
2032	259,607	33484	36587	892
2033	261,932	33772	36840	894
2034	264,256	34059	37094	897
2035	266,581	34347	37347	899
2036	268,906	34635	37600	901
2037	271,231	34923	37853	903
2038	273,556	35211	38106	905

INGAA calculated the low and high costs based on unit cost data included in the PRIA and the incremental patrol frequency compared to the current regulatory patrol frequency requirements: 11 additional patrols in Class 1 and Class 2, 10 additional patrols in Class 3, and eight patrols in Class 4 locations respectively.

Table 6: Recalculated Summary of Incremental Patrol Costs (annualized with 3 and 7 percent discount rate)

Year	Low Cost: $32 ($M)	High Cost: $128 ($M)
2024	$108	$430
2025	$108	$434
2026	$109	$437
2027	$110	$441
2028	$111	$445
2029	$112	$449
2030	$113	$453
2031	$114	$456
2032	$115	$460
2033	$116	$464
2034	$117	$468
2035	$118	$472
2036	$119	$476
2037	$120	$480
2038	$121	$484
3% Total	**$1,398**	**$5,591**
7% Total	**$1,101**	**$4,405**
3% Annualized	**$93**	**$373**
7% Annualized	**$73**	**$294**

Thus, assuming for argument that PHMSA's unit cost values are accurate, the estimated cost impacts of increasing the patrol frequency to 12 times per year is between $93 million and $373 million per year based on annualized costs using a three percent discount rate.

The agency does not identify any benefits associated with increasing the frequency of right-of-way patrols for all transmission pipelines to 12 times per year. INGAA agrees that right-of-way patrols allow an operator to view encroachments or class changes, and some operators may choose to patrol their rights-of-way more frequently. Yet, PHMSA clearly states in the NPRM that visual inspection of rights-of-ways is no longer acceptable to the agency for leakage survey purposes. Therefore, it is questionable why adding between eleven and eight additional patrols per year, are necessary, if they are not used for leak detection purposes.

IV. Leak Survey Cost Recalculations

PHMSA estimated in its PRIA that the costs associated with the new ALDP requirements would be $12 million. This cost is incorrect. PHMSA based its per mile cost for leakage surveys on information from a single operator. [28] That operator's mileage and system parameters are not

[28] PRIA, at 41.

indicative of the entire industry. In fact, one INGAA member estimated that their costs alone would increase by $24 million a year using PHMSA's assumed rate of $515 per mile. The Agency also acknowledged that it "did not find good estimates of the costs of conducting leak surveys using traditional survey methods only and therefore lacked sufficient information to determine whether the transition to ALD[P] methods results in an incremental cost per mile basis."[29] PHMSA has the authority and the obligation to gather this data to meet the cost/benefit mandates of the Pipeline Safety Act and to create a baseline and compare with the costs of the proposed rule in accordance with the OMB guidance. Here, PHMSA has not established an appropriate baseline. PHMSA should re-evaluate its assessment of the costs associated with its ALDP and leakage survey requirements.

PHMSA calculated the leakage surveys for a subset of natural gas transmission lines that are considered by PHMSA to be leak-prone pipe or in an HCA (PHMSA determined 7% of mileage is within an HCA by class). PHMSA calculated the mileage estimates using a number of assumptions, such as that all intrastate Class 3 and 4 mileages are odorized, and all other interstate lines operate without odorant—this is an important distinction and unfortunately the Agency's assumptions are inconsistent with its regulations and current practices of operators. Section 49 CFR 192.706 currently provides leak survey requirements for odorized and non-odorized Class 3 and 4 locations, however, odorized vs. non-odorized mileage is not tracked in PHMSA annual report data. PHMSA itself recognized that their assumptions are simplistic stating that the "assumption affects the modeled frequency of leakage surveys for different types of transmission lines under the baseline and proposed rule."[30] PHMSA used the assumed HCA and leak prone pipe mileage and multiplied by the incremental leak survey frequency in Class 1 and 2 locations, resulting in one additional survey in each respective class location. PHMSA determined the unit survey cost of $515 per mile would be uniformly applied to all impacted mileage (no baseline versus proposed regulatory incremental cost). PHMSA asserted that this overstates the cost impacts for this provision. However, PHMSA inaccurately assessed the cost for leak survey based on two distinct flaws. First, the PRIA does not consider the additional mileage that will need to be surveyed for additional pipeline miles, which in fact more than doubles the mileage impact. Second, PHMSA failed to account for the cost of using ALD equipment with minimum sensitivities as compared to the current regulatory requirements for leak surveys. Therefore, the Agency significantly underestimated the cost of conducting leak surveys as specified in the NPRM. Although the unit cost of $515 per mile may be a reasonable estimate for the leak detection surveys conducted under the current regulations, the cost per mile under a new ALD technology standard will likely be higher.

INGAA calculated the cost impacted based on two factors. Tables 7 through 10 show the approach INGAA used in assessing the actual industry impact, which includes an increase in the frequency in leak surveys in Class 1 and 2 locations and the cost of adhering to the leak survey ALD requirements in the NPRM. The Association requests that the Agency re-examine the cost and mileage impacts as it relates to leak survey.

[29] PRIA, at 41.
[30] PRIA, at 23.

Incremental Leak Survey Frequency Requirement

INGAA recalculated the incremental survey requirement in the NPRM by determining the amount of Class 1 and Class 2 mileage that would be impacted. PHMSA's mileage estimate only included HCA and leak-prone pipe in Class 1 and 2 locations but failed to incorporate the number of facilities that would be required to perform additional leak surveys. INGAA estimates that these facility surveys would vary based on class, resulting in a facility every 20 miles in a Class 1 and every 15 miles in a Class 2 location. The amount of impacted mileage totals 30,845 in Class 1 and 4,490 in Class 2. Note that the Agency did not provide mileage breakouts for HCA and leak-prone pipe, or the amount of odorized pipeline in these class locations. PHMSA should include these mileage estimates as it reassesses the cost impacts.

Table 7: Incremental Mileage Impacts by Class

Class Location	Total 2020 Mileage	HCA Mileage: 7% of All Mileage	2020 Bare Steel (3504 miles) Annual Report	Aboveground Facilities per Mile	Aboveground Facilities	Total Impacted Mileage
Class 1	234178	16392	2744	20	11709	30845
Class 2	30259	2118	355	15	2017	4490
Class 3	33775	2364	396	8	4222	6982
Class 4	866	61	10	4	217	287

Using the PHMSA unit cost of $515 for ALD, which as noted above is too low, the Association calculates the addition of 1 leak survey in Class 1 and Class 2 locations at $18 million annually.

Table 8: Increased Frequency of Leak Survey Cost Impacts in Class 1 and 2 Locations (2020$)

Class Location	Total Impacted Survey Mileage	Additional Leak Survey Frequency	Cost of ALD	Total Additional Survey
Class 1	30845	1	$515	$15,885,170
Class 2	4490	1	$515	$2,312,304
			TOTAL	$18,197,475

Incremental Cost of the ALD Survey

INGAA also calculated the incremental cost of moving to ALD using the PHMSA unit cost of $515 per mile (less $128) which is assumed as the baseline cost in the leak patrol section of the PRIA. This results in the following cost calculations by class, totaling over $138 million annually using 2020 mileage estimates.

Table 9: Increased Cost of Leak Surveys Using ALD Methods (2020$)

Survey Frequency less Incremental Survey in Class 1 and 2	Incremental Cost of ALD $515 - $128 = $387	Total mileage by Class	TOTAL Incremental Cost
Class 1: 1 survey	387	245887	$95,158,230
Class 2: 1 survey	387	32276	$12,490,915
Class 3: 2 surveys	387	37997	$29,409,581
Class 4: 4 surveys	387	1083	$1,675,710
		TOTAL	$138,734,437

Adding the cost of the incremental survey plus the incremental cost of ALD, the total equates to over $128 million annually using a 3 percent discount rate.

Table 10: Total Leak Survey Cost

Year	Incremental Survey Frequency	Incremental Cost of ALD Survey	TOTAL Incremental ($M)
2024	$18	$139	$157
2025	$18	$139	$157
2026	$18	$139	$157
2027	$18	$139	$157
2028	$18	$139	$157
2029	$18	$139	$157
2030	$18	$139	$157
2031	$18	$139	$157
2032	$18	$139	$157
2033	$18	$139	$157
2034	$18	$139	$157
2035	$18	$139	$157
2036	$18	$139	$157
2037	$18	$139	$157
2038	$18	$139	$157
3%			$1,927.42
7%			$1,527.65
3% Annualized			$128.49
7% Annualized			$101.84

V. Leak Repair Cost Recalculations

The agency's conclusion that repairing a leak costs $5,650, or with follow up activities, $5,868 per leak, is unsubstantiated and incorrect. PHMSA based this calculation on a utility rate case involving a single operator. PHMSA first multiplied the annual transmission mileage by a leak rate of 0.0046 per mile, which the Agency inexplicitly used as a baseline for the number of total annual leaks. PHMSA then applied a higher average leak rate of 0.0053961 per mile using ALD to determine the incremental leak rate. The incremental leaks were then multiplied by the repair cost of $5,868. The Association believes that this is not an appropriate method for estimating these cost impacts and is an oversimplification of the complexity of repairing leaks, particularly on valves and other transmission facilities that could be substantially more expensive than $5,868 per leak to repair.

PHMSA should use its information-gathering authority to obtain accurate information from across the industry on the costs for repair. Then PHMSA should recalculate the cost of leak repair to include the initial investigation of all potential leaks (positive and false positives), account for the cost of investigating each actual leak based on requirements in the NPRM, the empirical information on repair costs, and increase the amount of time/labor cost of the leak repair confirmation. To estimate the cost, INGAA developed a four-step process:

1. **Investigation of all indications of a leak:** For purposes of this calculation, the Association determined that using a 5 ppm ALD method could result in a 0.078 per mile indication of a leak—that includes both actual leaks and false indications of a leak. This rate was determined by an operator who had used a 5-ppm sensitivity in previous operational years and tracked both the false positives and actual leaks on their 500-mile system. While this is a limited sample it is indicative of the false positive rates that several operators have experienced. Applying the same rate and taking 2024 mileage of 308,972 x 0.078 into consideration results in 24,100 potential leaks, which all must be investigated. The Association believes that each indication of a leak will result in six hours of a technician's time to investigate each potential leak at a labor rate of $72.61. Therefore, the annual cost for investigation of all potential leaks is over $10.5 million (24,100 x 6 hours x $72.61 starting in 2024).

   However, INGAA also used data provided by a service provider from Europe that specializes in laser based aerial leak detection for gas pipelines. According to customer feedback using this specific technology, 75% of gas indications were actual leaks, while 25% of leaks were false positives.[31] Therefore, adding an additional sensitivity for cost associated with positive leaks identified in the PRIA plus a 25% increase for false positives, the indications of a potential leaks are calculated in Table 11 to show the lower and higher number of indications of a leak.

   Technician labor is based on member feedback and includes a $38 hourly rate, $5 equipment use per hour (fuel, maintenance, toll tags, vehicle depreciation), $10 miscellaneous costs (fire retardant clothing rental, steel toed boots, gloves, tooling, tooling

[31] https://www.socalgas.com/regulatory/documents/r-15-01-008/Adlares%20GmbH.pdf, at 18.

calibration costs, etc.) and 37% benefits loading (training, health insurance, retirement, life insurance, 401k match, social security, PTO). The total technician cost is $72.61 per hour.

Using these costs, the Association calculated the following in Table 11:

Table 11: Potential Indications of a Leak Using 5ppm ALD Sensitivity

Year	Mileage	LOW Supplier Indication of a leak (ALD positive leaks + 25% false leaks)	HIGH Operator Detection Rate with 5ppm (.078/mile)	LOW Investigation of Indication of Leak (includes 6 hrs. of technician time at $72.61 labor rate) [$M]	HIGH Investigation of Indication of Leak (includes 6 hrs. of technician time at $72.61 labor rate) [$M]
2024	308972.6	2084	24,100	$.9	$10
2025	311489.8	2101	24,296	$.9	$11
2026	314007	2118	24,493	$.9	$11
2027	316746	2136	24,706	$.9	$11
2028	319485	2155	24,920	$.9	$11
2029	322224	2173	25,133	$.9	$11
2030	324963	2192	25,347	$1.0	$11
2031	327702	2210	25,561	$1.0	$11
2032	330570	2230	25,784	$1.0	$11
2033	333438	2249	26,008	$1.0	$11
2034	336306	2268	26,232	$1.0	$11
2035	339174	2288	26,456	$1.0	$12
2036	342042	2307	26,679	$1.0	$12
2037	344910	2326	26,903	$1.0	$12
2038	347778	2346	27,127	$1.0	$12

2. **Investigation of Leaks:** As noted above, PHMSA should use its information gathering authority to solicit actual data from operators. However, assuming that PHMSA baseline and incremental leak rate are relatively accurate (.0046 baseline and 0.0053961 with ALD methods), the incremental leaks are approximately 246 in 2024 and increases by year based on mileage adjustments. To investigate a leak based on requirements in the NPRM, the Association had an operator pull the cost to conduct the necessary metallurgical lab work which was $5,865 per leak. The total to write the investigation report would require 12 hours of staff time at a blended rate of $76.63 (which is outlined in Table 18 of the PRIA for reporting purposes). Total cost of incremental leaks x $5,865 + leaks x $919.56 equates to $2.9 million (2024). Using these costs, the Association calculated the following in Table 12:

Table 12: Investigations of a leak

Year	85% Baseline Leaks (.0046/mile)	100% Leaks with ALD (.0053961/mile)	Incremental Leaks	Investigation of Leak ($5865/Investigation + 3 people x 4 hrs. at $76.63) [$M]
2024	1421	1667	246	$2
2025	1433	1681	248	$2
2026	1444	1694	250	$2
2027	1457	1709	252	$2
2028	1470	1724	254	$2
2029	1482	1739	257	$2
2030	1495	1754	259	$2
2031	1507	1768	261	$2
2032	1521	1784	263	$2
2033	1534	1799	265	$2
2034	1547	1815	268	$2
2035	1560	1830	270	$2
2036	1573	1846	272	$2
2037	1587	1861	275	$2
2038	1600	1877	277	$2

3. **Repairing Leaks:** Very few operators have readily available data on the cost per repair for a leak. Given the deadline to provide these comments, the Association was not able to gather empirical data from multiple operators. However, PHMSA has information gathering authority which it should use to do just that – gather empirical data from across the industry so that the revised PRIA is based on actual costs.

   For the purposes of this analysis and to demonstrate the obvious errors in the PHMSA calculations, the Association made conservative assumptions. While these assumptions are not concrete enough to meet the cost/benefit requirements of the Pipeline Safety Act, they do demonstrate that PHMSA's calculated cost per leak is far too low. One of the conservative assumptions the Association made is that of the incremental leaks found in part two of this process, the majority, 70 percent, would be at the cost currently included in the PRIA of $5,650 per leak. The leaks that would likely fall into this low-cost category are minor leaks that could be repaired with a grease gun or with limited equipment, such as a wrench—essentially leaks that could be fixed within a day or two. The Association then assumed that 20 percent of leaks would require a medium cost to repair of $20,000. Medium cost repairs would include replacing a small diameter valve for example, which is easy to isolate. Lastly, the Association assumed that approximately 10 percent of leaks would require a higher cost to repair, such as a valve packing repair with isolation of a mainline valve segment and blowdown mitigation. The cost for these repairs is typically over $100,000, without considering the service disruption impacts which should be included in PHMSA's subsequent analysis. Multiplying the low, medium, and high leak by the repair costs equates to over $4 million annually (excluding costs of service disruptions). Using these assumptions, the Association recalculated the following values which demonstrates that PHMSA's calculations were erroneous:

Table 13: Low, Medium, High Repair Costs

Year	Low ($M)	Medium ($M)	High Cost ($M)	Total Repair ($M)
2024	$1	$1	$2	$4
2025	$1	$1	$2	$4
2026	$1	$1	$2	$4
2027	$1	$1	$3	$5
2028	$1	$1	$3	$5
2029	$1	$1	$3	$5
2030	$1	$1	$3	$5
2031	$1	$1	$3	$5
2032	$1	$1	$3	$5
2033	$1	$1	$3	$5
2034	$1	$1	$3	$5
2035	$1	$1	$3	$5
2036	$1	$1	$3	$5
2037	$1	$1	$3	$5
2038	$1	$1	$3	$5

4. **Post Repair Confirmation:** The Association calculated the post repair confirmation at the technician rate in step 1 of $72.61 per hour and assumed that the confirmation process would take approximately 4 hours of time. The cost of performing the confirmation is estimated in Table 14.

Table 14: Post Repair Confirmation Labor Costs

Year	Post Repair Confirmation (4 hours at $72.61 labor rate) [$M]
2024	$.07
2025	$.07
2026	$.07
2027	$.07
2028	$.07
2029	$.07
2030	$.08
2031	$.08
2032	$.08
2033	$.08
2034	$.08
2035	$.08
2036	$.08
2037	$.08
2038	$.08

Combining the costs in the four-step process, results in an annual cost as outlined in Table 15. This far exceeds PHMSA's estimated cost of $1.5 million per year.

Table 15: Total cost of performing leak repairs

Year	LOW: Step 1 Indication of Leak ($M)	HIGH: Step 1 Indication of Leak ($M)	Step 2 Investigation of Leak ($M)	Step 3 Repairing Leaks ($M)	Step 4 Post Repair Confirmation ($M)	LOW: Total Leak Repair Process Cost ($M)	HIGH: Total Leak Repair Process Cost ($M)
2024	$.9	$10	$2	$4	$.07	$7	$17
2025	$.9	$11	$2	$4	$.07	$7	$17
2026	$.9	$11	$2	$4	$.07	$7	$17
2027	$.9	$11	$2	$5	$.07	$7	$17
2028	$.9	$11	$2	$5	$.07	$7	$17
2029	$.9	$11	$2	$5	$.07	$7	$17
2030	$1.0	$11	$2	$5	$.08	$7	$18
2031	$1.0	$11	$2	$5	$.08	$7	$18
2032	$1.0	$11	$2	$5	$.08	$8	$18
2033	$1.0	$11	$2	$5	$.08	$8	$18
2034	$1.0	$11	$2	$5	$.08	$8	$18
2035	$1.0	$12	$2	$5	$.08	$8	$18
2036	$1.0	$12	$2	$5	$.08	$8	$18
2037	$1.0	$12	$2	$5	$.08	$8	$19
2038	$1.0	$12	$2	$5	$.08	$8	$19
					3% Total	**$89**	**$217**
					7% Total	**$68**	**$171**
					3% Annualized	**$5.9**	**$14.5**
					7% Annualized	**$4.5**	**$11.4**

VI. Conclusion

In summary, INGAA urges PHMSA to revise the benefit and cost impacts contained in the PRIA to address the following limitations in its analysis:

- The current cost effectiveness of the proposed rule is not reasonable under cost/benefit provisions of the Pipeline Safety Act and the OMB guidance. PHMSA should establish a cost effectiveness threshold similar to EPA's established upper-bound cost effective threshold for methane reduction. PHMSA must reevaluate the rule based on a full range of costs and benefits, including a cost effectiveness evaluation to ensure that the $/metric ton of methane reduction is more accurately calculated.
    - To achieve a 627 metric ton methane reduction, INGAA estimates that gas transmission operators will spend between $228-$516 million annually, while PHMSA reports a $14.9 million cost annually. This cost difference demonstrates the significant concerns in the PHMSA evaluation, both in terms of how costly

this rule is to implement and how relatively small the emission reductions are annually.
  - Reducing a single metric ton of methane will cost the gas transmission industry between $363,636-$822,967.
  - Even assuming that the PHMSA calculations are accurate, which they are not, the cost effectiveness of the rule is unreasonable according to EPA standards, with a cost of $23,763 to reduce one metric ton of methane.
  - Using a similar analysis to EPA's established upper-bound cost effective threshold for methane reduction to achieve a reduction of 627 metric tons of methane, the total implementation cost of the rule for the gas transmission industry should be approximately $1.28 million annually.

- Reassess the benefit calculations in the PRIA to reflect appropriate leak reductions, alignment with other regulations, voluntary measures, and advancements in technology.
  - The annual changes to methane emissions are estimated in Table 33 of the PRIA and range from a reduction of -1,300 to -10,100 metric tons of CH_4 annually.[32]
  - Including an inventory of emissions prior to the effective date of the rule should not be part of reduction emission calculation.
  - PHMSA uses the EPA 10.9 kg/mile parameter to quantify leaks and this value is based on GRI/EPA 1996 data sources, which are outdated. Additionally, the outdated EPA emission factor for gas transmission is modeled on the average leakage rate for distribution main pipelines.[33]
  - The assumption that the increase in pipeline mileage results in more leaks over time. It was PHMSA's expectation that the implementation of RIN2137-AF39 would reduce leaks and ruptures to the industry and thus the justification for the rule. Further, industry has shown that implementing reoccurring LDAR programs have a diminishing return over time. Results have shown that the first survey identifies and remedies most leaks, resulting in less leaks per year.[34] The PRIA assumes that leaks will increase annually. Thus, the annual emission reductions will be less over time.

- Use an appropriate baseline established on current regulatory requirements compared to the proposed compliance activities outlined in the NPRM to calculate the incremental impacts.
  - The assumption that all gas transmission operators currently patrol their rights-of-way (ROWs) monthly is incorrect. This assumption significantly understates the costs by $93-$373 million annually.

- Gather empirical unit cost data from across the industry so that the revised PRIA is based on actual cost data.

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[32] PRIA, at 74.
[33] https://www.epa.gov/sites/default/files/2016-08/documents/9_underground.pdf, at 38.
[34] https://www.api.org/~/media/files/news/letters-comments/2015/15-december/api-comments-on-nsps-12042015.pdf API comments to Docket ID Number EPA-OAR-2015-0216, at 124.

- Create mileage estimates that accurately reflect all impacted facilities according to the compliance activities outlined in the NPRM.
    - PHMSA did not account for valves and other aboveground facilities that will be required to be surveyed by class and frequency.
    - Growth in transmission pipeline mileage year over year appears to be overly optimistic and unsupported by PHMSA and EIA data. This is especially true given current permitting and construction constraints.

- Incorporate cost impacts that value the entire process of each proposed compliance requirement.
    - PHMSA needs to include the total cost impacts of moving to a 5ppm ALD sensitivity that increases the amount of false positive leaks that will need to be investigated.
    - Include costs for investigating leaks that now require metallurgical lab analysis and reports.
    - Obtain operator data on the cost of repairing leaks that reflect a broader set of inputs based on the certain types/characteristics of repairs.

- Evaluate the costs of requiring gas transmission operators to fix all leaks within a six-month timeframe, including the unintended consequence of potential service disruptions, supply constraints and impacts on markets.

- Evaluate the impacts of adding the new definition of a failure throughout Part 192

While the Association acknowledges that PHMSA included sensitivities in the PRIA, such as alternatives and sections on uncertainty, INGAA concludes that without an accurate approach to analyzing costs, policymakers are unable to determine the reasonable effectiveness of the proposed rule or appropriate regulatory alternatives. INGAA recommends PHMSA reassess the cost and benefit calculations in the PRIA and develop accurate impacts.