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Docket No. PHMSA-2021-0039

GAS GATHERING INDUSTRY COMMENTS

submitted by the

GPA MIDSTREAM ASSOCIATION,
AMERICAN PETROLEUM INSTITUTE,
INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA,
MARCELLUS SHALE COALITION,
PENNSYLVANIA INDEPENDENT OIL & GAS ASSOCIATION,
GAS & OIL ASSOCIATION OF WEST VIRGINIA,
OHIO OIL & GAS ASSOCIATION,
KENTUCKY OIL & GAS ASSOCIATION,
TEXAS OIL & GAS ASSOCIATION, and
THE PETROLEUM ALLIANCE OF OKLAHOMA

in response to

"Pipeline Safety: Gas Pipeline Leak Detection and Repair," RIN 2137-AF51

Notice of Proposed Rulemaking Published by the Pipeline and Hazardous Materials Safety Administration,
U.S. DEPARTMENT OF TRANSPORTATION,
88 Fed. Reg. 31,890 (May 18, 2023)

Filed August 16, 2023

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I. Introduction

On May 18, 2023, the Pipeline and Hazardous Materials Safety Administration (PHMSA or the Agency) published a proposed rule in the *Federal Register* in Docket No. PHMSA-2021-0039 (Proposed Rule).[1] The Proposed Rule includes significant changes to the reporting requirements in 49 C.F.R. Part 191 and safety standards in 49 C.F.R. Parts 192 for gas pipeline facilities. PHMSA proposed these changes primarily to address certain provisions in the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (2020 PIPES Act).[2]

The GPA Midstream Association (GPA),[3] American Petroleum Institute (API),[4] Independent Petroleum Association of America (IPAA),[5] Marcellus Shale Coalition (MSC),[6] Pennsylvania Independent Oil & Gas Association (PIOGA),[7] Gas & Oil Association of West Virgina (GO-WV),[8] Ohio Oil & Gas Association (OOGA),[9] Kentucky Oil & Gas Association

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[1] Pipeline Safety: Gas Pipeline Leak Detection and Repair, 88 Fed. Reg. 31,890 (May 18, 2023) (Proposed Rule).
[2] Pub. L. No. 116-260, Division R, 134 Stat. 1181, 2210.
[3] GPA Midstream has served the U.S. energy industry since 1921. GPA Midstream is composed of nearly 60 corporate members that directly employ 55,000 employees that are engaged in the gathering, transportation, processing, treating, storage and marketing of natural gas, natural gas liquids (NGLs), crude oil and refined products, commonly referred to in the industry as "midstream activities." In 2022, GPA Midstream members operated over 495,000 miles of pipelines, gathered over 85 Bcf/d of natural gas and produced over 4.6 million barrel/day of NGLs from over 375 natural gas processing facilities.
[4] API is the national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and 8 percent of the U.S. economy. API's more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 25 million Americans.
[5] IPAA represents thousands of independent oil and natural gas producers and service companies across the United States. America's independent producers develop 91 percent of the nation's oil and natural gas wells.
[6] MSC is a regional trade association with a national membership. The MSC was formed in 2008 and is currently comprised of approximately 140 producing, midstream, transmission and supply chain members who are fully committed to working with local, county, state and federal government officials and regulators to facilitate the development of the natural gas resources in the Marcellus, Utica and related geological formations. Our members represent many of the largest and most active companies in natural gas production, gathering, processing and transmission, in the country, as well as the suppliers, contractors and professional service firms who work with the industry.
[7] PIOGA is Pennsylvania's trade association representing Pennsylvania independent oil and natural gas producers of natural gas from both conventional (tight sand/sandstone) and unconventional (organic shale) formations. PIOGA and its producer members support reasonable reporting requirements and gas pipeline safety standards based on the application of risk management principles, cost/benefit analyses and the other considerations specified in federal law.
[8] GO-WV is an association of oil and gas-related companies doing business in the State of West Virginia. GO-WV's members are engaged in the exploration, production, gathering, distribution, transportation, and sale of natural gas.
[9] OOGA is a trade association with members representing the people and companies directly responsible for the production of crude oil, natural gas, and associated products in Ohio. The core OOGA membership is comprised of independent oil and natural gas producers, major national oil and natural gas producing companies, and major international oil and natural gas companies—all focused on the exploration, discovery, and production of crude oil, natural gas, and associated liquids in Ohio.

(KYOGA),[10] and the Texas Oil & Gas Association (TXOGA),[11] and The Petroleum Alliance of Oklahoma (PAO)[12] (collectively, Gas Gathering Industry Commenters) are respectfully submitting the following comments on the proposals for onshore gas gathering lines.[13]

II. Summary

The Gas Gathering Industry Commenters support the Agency's efforts to prescribe gas pipeline leak detection and repair (LDAR) regulations pursuant to the requirements in Section 113 of the 2020 PIPES Act. Congress directed the Agency in Section 113 to establish minimum performance standards for LDAR programs and to require the use of advanced leak detection technologies and practices for certain types of gas pipeline facilities; namely, gas distribution lines, gas transmission lines, and regulated onshore gas gathering lines in more populated Class 2, 3, and 4 locations. The Gas Gathering Industry Commenters appreciate that PHMSA has an obligation to act expeditiously in satisfying Congress' instructions, that the policy preferences of the executive branch will be taken into account in meeting that objective, and that reducing methane emissions is a priority for the current administration, the pipeline industry, and other interested stakeholders.

But Section 113 of the 2020 PIPES Act did not suspend the Agency's obligation to follow the law in prescribing LDAR regulations for gas pipeline facilities. The Pipeline Safety Act requires PHMSA to conduct a risk assessment in developing proposed safety standards, and that risk assessment must identify the regulatory and non-regulatory options considered, explain why the options identified were either selected or rejected, identify the associated costs and benefits, and describe the technical data or information relied upon in developing the proposed standard and risk assessment. As the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit) recently explained in *GPA Midstream Ass'n v. United States Dep't of Transportation*, failing to comply with the Pipeline Safety Act's risk assessment requirements is a "serious error" that deprives the

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[10] KYOGA was formed in 1931 to represent the interests of Kentucky's crude oil and natural gas industry, and more particularly, the independent crude oil and natural gas operators. Our goals include promoting, protecting and advancing the interests of the oil and gas industry; opposing any unfair and unjust legislation which may adversely affect the oil and gas industry; and, disseminating reliable publicity to further and protect the oil and gas industry. KYOGA is dedicated to the responsible production and conservation of Kentucky's natural resources, while ensuring that its members are provided fair regulations, are educated on oil and gas issues, while protecting individual property rights, health, safety, and the environment.

[11] TXOGA is a statewide trade association representing every facet of the Texas oil and gas industry including small independents and major producers. Collectively, the membership of TXOGA produces approximately 90 percent of Texas' crude oil and natural gas, operates nearly 90 percent of the state's refining capacity, and is responsible for the vast majority of the state's pipelines. In fiscal year 2022, the Texas oil and natural gas industry supported 443,000 direct jobs and paid $24.7 billion in state and local taxes and state royalties, funding our state's schools, roads and first responders.

[12] PAO represents more than 1,400 individuals and member companies and their tens of thousands of employees in the upstream, midstream, and downstream sectors and ventures ranging from small, family-owned businesses to large, publicly traded corporations. Our members produce, transport, process and refine the bulk of Oklahoma's crude oil and natural gas.

[13] PHMSA originally requested that any comments be filed by no later than July 17, 2023, but later extended the comment period until August 16, 2023. Pipeline Safety: Gas Pipeline Leak Detection and Repair, 88 Fed. Reg. 42,284 (Jun. 30, 2023).

public and the Gas Pipeline Advisory Committee (GPAC) of the opportunity to participate in the rulemaking process.[14]

PHMSA committed that serious error in developing the LDAR regulations for onshore gas gathering lines in the Proposed Rule. In conducting the risk assessment for Type C gas gathering lines—which only became jurisdictional last year and are not subject to the rulemaking mandate in Section 113—PHMSA failed to consider any non-regulatory options, erroneously limited its consideration of the available regulatory options, failed to reasonably identify the costs and benefits, and relied on inadequate technical data and information. The Agency made similar mistakes in conducting the risk assessment for Type A and Type B gathering lines, *e.g.*, PHMSA relied on flawed cost assumptions, ignored critical economic differences between the gathering and transmission sectors, and failed to quantify any of the expected safety benefits, even though those benefits predominate in evaluating the proposals that would require the detection, grading, and repair of small leaks.

The defects in the Proposed Rule go well beyond the Agency's failure to comply with the Pipeline Safety Act's risk assessment requirements. The proposal to require gathering line operators to participate in the National Pipeline Mapping System (NPMS) is unlawful. The proposed definition of "leak or hazardous leak" is inconsistent with longstanding regulatory precedent and industry practice, the text of Section 113, the U.S. Environmental Protection Agency's (EPA) LDAR regulations, and common usage and understanding. The proposals for right-of-way (ROW) patrolling, conducting leak surveys, and the criteria for the grading and repair of leaks lack adequate record support and are otherwise unreasonable. The proposed advanced leak detection program (ALDP)—which requires operators to deploy advanced leak detection technologies but then effectively prohibits the use of those technologies by imposing a detectability threshold that is 10,000 times below the lower explosive limit of natural gas and 100 times more conservative than EPA's comparable requirements—is a lose-lose proposition that does not promote public safety or protect the environment.

The Gas Gathering Industry Commenters do not object to all aspects of the Proposed Rule. The proposed reporting requirement for large-volume gas releases is a reasonable concept, although improvements are needed to eliminate unnecessary provisions and duplicative reporting obligations. The proposal to clarify that operators of Type B and C gathering lines must develop and implement a manual of written procedures for conducting operations, maintenance, and emergency response activities is also reasonable in principle, so long as the final rule aligns with the risk assessment and current regulatory obligations. The Gas Gathering Industry Commenters support the proposed exception from the LDAR requirements for compressor station facilities that are subject to EPA's methane emission monitoring and repair requirements and encourage PHMSA to expand that exception to other facilities and requirements.

Despite these limited areas of agreement, the Agency has left itself with no choice but to return to the drawing board in developing the proposed LDAR requirements for onshore gas gathering lines. PHMSA's failure to comply with the risk assessment requirements and the significant substantive flaws in the Proposed Rule cannot be cured without further internal deliberation and the opportunity for additional public notice and comment. Accordingly, the Gas

[14] *GPA Midstream Ass'n v. United States Dep't of Transp.*, 67 F.4th 1188, 1197 (D.C. Cir. 2023).

Gathering Industry Commenters respectfully request that PHMSA defer any further consideration of the proposed LDAR requirements for onshore gas gathering lines until a subsequent rulemaking proceeding.

III. Background

a. Sections 113 and 114 of 2020 PIPES Act

On December 27, 2020, the 2020 PIPES Act was signed into law. In addition to reauthorizing the federal pipeline safety program through September 30, 2023, the 2020 PIPES Act amended certain provisions in the Pipeline Safety Act.[15] Two of those amendments are relevant to many of the requirements proposed in this proceeding. The first amendment, adopted in Section 113 of the 2020 PIPES Act and currently codified at 49 U.S.C. § 60102(q), added a rulemaking mandate to the Pipeline Safety Act directing PHMSA to issue new gas pipeline LDAR regulations by December 27, 2021.[16] The scope of that rulemaking mandate is limited to certain regulated onshore gathering lines in Class 2, 3, or 4 locations.[17] It does not extend to onshore gas gathering lines in Class 1 locations, which only recently became subject to the Agency's jurisdiction under the Pipeline Safety Act after being exempt for more than five decades.[18]

The second amendment, adopted in Section 114 of the 2020 PIPES Act and currently codified, in part, at 49 U.S.C. § 60108(a)(2)(D)-(E), amended the factors that PHMSA and state pipeline safety authorities are required to consider in deciding on the adequacy of inspection and maintenance plans.[19] Those additional factors include "the extent to which the plan will contribute to . . . eliminating hazardous leaks and minimizing releases of natural gas from pipeline facilities . . . [and] addresses the replacement or remediation of pipelines that are known to leak based on the material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history of the pipeline."[20] Section 114 also contained an uncodified mandate directing operators of gas pipeline facilities to update their inspection and maintenance plans by December 27, 2021, to address the new factors in 49 U.S.C.

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[15] 49 U.S.C. § 60101 *et seq.*

[16] 2020 PIPES Act § 113 (codified at 49 U.S.C. § 60102(q)(1)).

[17] Section 60102(q)(1) specifically states, in relevant part, that the gas pipeline leak detection and repair rulemaking mandate only applies to "operators of regulated gathering lines (as defined pursuant to subsection (b) of section 60101 for purposes of subsection (a)(21) of that section) in a Class 2 location, Class 3 location, or Class 4 location, as determined under section 192.5 of title 49, Code of Federal Regulations[.]" 49 U.S.C. § 60102(q)(1). Section 60101(b), one of the two provisions referenced in the foregoing limitation, is a statutory provision that Congress added to the Pipeline Safety Act in the Pipeline Safety Act of 1992, Pub. L. No. 102-508, § 109(b), § 208(b), 106 Stat. 3289, 3295, 3303-3304 ("1992 Act"), as recodified by Pub. L. 103–272, (1994), 108 Stat. 1301, and amended by the Accountable Pipeline Safety and Partnership Act of 1996 Pub. L. No. 104-304, § 12, 110 Stat. 3793, 3802, and which included a rulemaking mandate directing the Agency to define the term gathering line and issue safety standards for regulated gathering lines. PHMSA responded to that rulemaking mandate in the March 2006 final rule that established risk-based regulations for onshore gas gathering lines in 49 C.F.R. Part 192. Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 Fed. Reg. 13,289 (Mar. 15, 2006). Those regulations, which were in effect when the President signed the 2020 PIPES Act into law, only applied to onshore gas gathering lines in Class 2 locations, Class 3 locations, and Class 4 locations.

[18] Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, 86 Fed. Reg. 63,266 (Nov. 15, 2021).

[19] 2020 PIPES Act § 114(a)(1)(A)(i) (codified at 49 U.S.C. § 60108(a)(2)).

[20] *Id.* § 114(a)(1)(A)(iii), 134 Stat. at 2230 (codified at 49 U.S.C. § 60108(a)(2)(D)-(E)).

§ 60108(a)(2)(D)-(E).[21] Like the rulemaking mandate in Section 113, the uncodified provision in Section 114 only applied to regulated onshore gas lines in Class 2, 3, and 4 locations.[22] It did not apply to onshore gas gathering lines in Class 1 locations, which were not jurisdictional gas pipeline facilities when Congress enacted that provision.[23]

b. May 2021 Public Meeting on Implementation of Sections 113 and 114

On May 5 and 6, 2021, PHMSA held a public meeting to discuss Sections 113 and 114 of the 2020 PIPES Act. During the meeting, Matt Hite, Vice President of Government Affairs, GPA, provided a detailed presentation on the relevance of these two provisions to onshore gas gathering lines. Pointing to the statutory language, Mr. Hite explained that the rulemaking mandate in Section 113 only applied to regulated onshore gas gathering lines in Class 2, 3, and 4 locations. Mr. Hite likewise explained that the uncodified provision in Section 114, which required operators of gas pipeline facilities to update their inspection and maintenance plans by December 27, 2021, only applied to regulated onshore gas gathering lines in Class 2, 3, and 4 locations.

Mr. Hite then discussed the differences between the LDAR requirements for regulated onshore gas gathering lines in Class 2, 3, and 4 locations and transmission and distribution lines. Mr. Hite noted that PHMSA only exercised jurisdiction over two categories of regulated onshore gathering lines at the time of the public meeting, *i.e.*, (1) Type A gathering lines, which included higher stress or higher operating pressure pipelines in Class 2, 3, or 4 locations, and (2) Type B gathering lines, which included lower stress or lower operating pressure pipelines in Class 2, 3, and 4 locations. Mr. Hite further noted that onshore gas gathering lines in Class 1 locations were not subject to the Agency's jurisdiction.

Mr. Hite went on to explain that Type A gathering lines, which generally present a higher potential risk to public safety, were subject to many of the same LDAR requirements as gas transmission lines, including the obligation to promptly repair hazardous leaks under 49 C.F.R. § 192.703(c); conduct pipeline ROW patrols at the intervals specified in 49 C.F.R. § 192.705; perform leak surveys at the intervals specified in 49 C.F.R. § 192.706; and make repairs as provided in §§ 192.711-192.719. On the other hand, Mr. Hite observed that Type B gathering lines, which generally present a lower potential risk to public safety, were only subject to the requirement to promptly repair hazardous leaks under 49 C.F.R. § 192.703(c) and conduct leak surveys at the intervals specified in 49 C.F.R. § 192.706.

Unlike gas transmission and distribution lines, Mr. Hite cautioned that gas gathering lines are not subject to public-utility-style economic regulation and cannot recover increased compliance costs from captive ratepayers. Mr. Hite explained that gas gathering line operators do not absorb increased compliance costs in the same way as transmission and distribution line

[21] *Id.* § 114(b), 134 Stat. 2231.

[22] That limitation is derived from the definitions in 49 U.S.C. § 60101(a) and the provisions for regulated gathering lines in 49 U.S.C. § 60101(b). 49 U.S.C. § 60101(a)(3) (defining a "gas pipeline facility" as "a pipeline, a right of way, a facility, a building, or equipment used in transporting gas or treating gas during its transportation"); 49 U.S.C. § 60101(a)(21)(B) (defining "transporting gas" to exclude the gathering of gas in rural areas except in regulated gathering lines).

[23] Certain onshore gas gathering lines in Class 1 locations became jurisdictional gas pipeline facilities for purposes of the Pipeline Safety Act effective as of May 16, 2022. *See* discussion in Section III(c) of these comments.

operators for that reason, particularly in the near term. Mr. Hite urged PHMSA to be mindful of these considerations in developing any new LDAR requirements for gas gathering lines. GPA and API reiterated the points that Mr. Hite made in his presentation in a supplemental comment letter submitted after the public meeting.[24]

c. November 2021 Final Rule for Onshore Gas Gathering Lines

On November 15, 2021, PHMSA published a final rule in the *Federal Register* amending the reporting requirement in 49 C.F.R. Part 191 and safety standards in 49 C.F.R. Part 192 for onshore gas gathering lines.[25] In that final rule, the Agency added two new categories of onshore gas gathering lines to the framework of regulated Type A and Type B onshore gas gathering lines that PHMSA had previously established in a March 2006 final rule.[26] The two new categories of onshore gas gathering lines incorporated historically unregulated, non-jurisdictional pipelines in Class 1 locations, effective as of May 16, 2022.

As a result of the changes prescribed in the November 2021 final rule, the Agency's regulations now recognize the following four categories of onshore gas gathering lines:

- *Type A regulated onshore gas gathering lines* include metallic lines with a maximum allowable operating pressure (MAOP) of 20 percent or more of specific minimum yield strength (SMYS), as well as nonmetallic lines with an MAOP of more than 125 pounds per square inch gauge (PSIG), in a Class 2, 3, or 4 location.

- *Type B regulated onshore gas gathering lines* include metallic lines with an MAOP of less than 20 percent of SMYS, as well as nonmetallic lines with an MAOP of 125 PSIG or less, in a Class 2 location (as determined under one of three formulas) or in a Class 3 or Class 4 location.

- *Type C regulated onshore gas gathering lines* include onshore gas gathering lines in Class 1 locations with an outside diameter greater than or equal to 8.625 inches and an MAOP that produces a hoop stress of 20 percent or more of SMYS for metallic lines, or more than 125 PSIG for non-metallic lines or metallic lines if the stress level is unknown.

- *Type R reporting-only gathering lines* include any onshore gas gathering lines in Class 1 or Class 2 locations that are not Type A, Type B, or Type C lines.

Operators of Type A, B, and C gathering lines must comply with certain reporting requirements in Part 191 and safety standards in Part 192. Operators of Type R lines are only

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[24] Comments from GPA Midstream Ass'n & American Petroleum Inst. (May 24, 2021), https://www.regulations.gov/comment/PHMSA-2021-0039-0004.

[25] Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, 86 Fed. Reg. 63,266 (Nov. 15, 2021).

[26] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 Fed. Reg. 13,289 (Mar. 15, 2006).

required to comply with certain incident and annual reporting requirements as prescribed in Part 191.

d. May 2023 Proposed Rule

On May 18, 2023, PHMSA published the Proposed Rule in the *Federal Register*[27] and added a Preliminary Regulatory Impact Analysis (PRIA) and other supporting materials to the docket.[28] The Proposed Rule contains significant changes to the regulations for onshore gas gathering lines, including provisions for conducting more frequent leakage surveys and ROW patrols, developing and implementing an ALDP, prescribing more restrictive leak grade and repair criteria, developing procedures for pressure relief and limiting devices, establishing new reporting requirements, and requiring operators of regulated Type A, B, and C gathering lines to provide data and information to the NPMS.

IV. Comments

a. The Risk Assessment for the Proposed LDAR Regulations for Type C Gathering Lines Fails to Satisfy the Requirements in the Pipeline Safety Act.

The Pipeline Safety Act requires the Agency to conduct a risk assessment for each pipeline safety standard proposed under 49 U.S.C. § 60102. Section 60102(b)(3) states that in conducting a risk assessment PHMSA must:

> (A) identify the regulatory and nonregulatory options that the [Agency] considered in prescribing a proposed standard;
> (B) identify the costs and benefits associated with the proposed standard;
> (C) include—
> (i) an explanation of the reasons for the selection of the proposed standard in lieu of the other options identified; and
> (ii) with respect to each of those other options, a brief explanation of the reasons that the [Agency] did not select the option; and
> (D) identify technical data or other information upon which the risk assessment information and proposed standard is based.[29]

PHMSA is required to make the risk assessment for a proposed safety standard "available to the general public" for comment and to present the risk assessment information to the GPAC for peer review.[30] Failing to comply with the Pipeline Safety Act's risk assessment requirements is a "serious error" that provides a basis for vacating any subsequent final rule.[31]

[27] Proposed Rule, 88 Fed. Reg. 31,890.
[28] PHMSA, Preliminary Regulatory Impact Analysis, Docket No. PHMSA-2021-0039 (Apr. 2023), https://www.regulations.gov/document/PHMSA-2021-0039-0019
[29] 49 U.S.C. § 60102(b)(3)(A)–(D).
[30] *Id.* § 60102(b)(4).
[31] *GPA Midstream Ass'n*, 67 F.4th at 1197.

PHMSA committed that serious error in developing the proposed LDAR requirements for Type C gathering lines. As a threshold matter, the PRIA makes clear that the Agency assumed in preparing the risk assessment that the rulemaking mandate in Section 113 applied to *all gas pipeline facilities*. But Section 113 does not apply to all gas pipeline facilities, or even to all gas gathering lines; it only applies to Type A and Type B gas gathering lines in Class 2, 3, and 4 locations. The Agency acknowledged as much in the Proposed Rule, stating that its legal authority for proposing the LDAR requirements for Type C gathering lines in Class 1 locations is derived from the discretionary, general rulemaking authority in 49 U.S.C. § 60102(a).[32]

Despite relying on its discretionary, general rulemaking authority, PHMSA failed to consider *any non-regulatory options* in conducting the risk assessment for the proposed LDAR standards for Type C lines. The Agency stated in the PRIA that doing so would be unlawful, *i.e.*, that "keeping the requirements in 49 C.F.R. Part 192 unchanged . . . would fail to fulfill the mandate that Congress placed on PHMSA in Section 113 of the PIPES Act of 2020."[33] But, again, the rulemaking mandate in Section 113 does not apply to gas gathering lines in Class 1 locations, nor is there any other provision in the Pipeline Safety Act that prohibits PHMSA from considering non-regulatory options in conducting the risk assessment for these pipelines. If anything, Congress' decision to exclude Class 1 gas gathering lines from the rulemaking mandate in Section 113 reinforces the Agency's obligation to consider non-regulatory options in developing proposed LDAR requirements for Type C lines. Regardless, the notion that Section 113 compelled the Agency to disregard its obligation to consider any non-regulatory options is simply wrong.[34]

PHMSA's failure to consider any non-regulatory options is extremely troubling. The Agency did not exercise jurisdiction over any gas gathering lines in Class 1 locations for more than five decades, and PHMSA's regulations for Type C gas gathering lines only went into effect in May 2022.[35] The initial compliance deadline for existing Type C lines did not run until May 16, 2023, two days before PHMSA's publication of the Proposed Rule,[36] and the Agency agreed *not to enforce* the initial compliance deadline for existing, smaller diameter lines until May 2024, providing operators with the additional time to comply with the new regulations.[37] Failing to consider any non-regulatory options in developing a proposed safety standard in these

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[32] PHMSA's assertion that 49 U.S.C. § 60101(b) provides the Agency with the authority to prescribe LDAR requirements for Type C onshore gas gathering lines is incorrect. Section 60101(b) provides PHMSA with the authority to (1) "prescribe standards defining the term 'gathering line'" and (2) "prescribe standards defining the term 'regulated gathering line'." Unlike the final rule that the Agency issued in November 2021, the Proposed Rule does not seek to modify the definition of a "gathering line" or "regulated gathering rule"; it seeks to apply additional safety standards to gas pipeline facilities that already meet those definitions. The legal authority for proposing such standards is necessarily derived from provisions in the Pipeline Safety Act other than Section 60101(b).

[33] PRIA at 19.

[34] *Carlson v. Postal Regulatory Comm'n*, 938 F.3d 337 (D.C. Cir. 2019) (holding that a rule is arbitrary and capricious if an agency fails to consider applicable statutory factors); *see also Sec'y of Labor v. Nat'l Cement Co. of Cal., Inc.*, 494 F.3d 1066, 1073 (D.C. Cir. 2007) (citing *Peter Pan Bus Lines, Inc. v. Fed. Motor Carrier Safety Admin.*, 471 F.3d 1350, 1354 (D.C. Cir. 2006) ("[D]eference to an agency's interpretation of a statute is not appropriate when the agency wrongly believes that interpretation is compelled by Congress." (internal quotation marks omitted)).

[35] Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, 86 Fed. Reg. 63,266 (Nov. 15, 2021).

[36] 49 C.F.R. § 192.9(g)(4).

[37] PHMSA, Notice of Limited Enforcement Discretion for Particular Type C Gas Gathering Pipelines (July 8, 2022), https://www.phmsa.dot.gov/news/notice-limited-enforcement-discretion-particular-type-c-gas-gathering-pipelines.

circumstances is inexplicable. At the very least, PHMSA should have considered a non-regulatory option that would have allowed Type C gathering line operators to comply with the first federal safety standards ever imposed before prescribing more stringent LDAR requirements, including an advanced leak detection and repair program. Instead, the Agency failed to consider any non-regulatory options at all.

The regulatory options that PHMSA considered are also inadequate. The PRIA makes clear that the Agency proceeded from the erroneous conclusion that the regulatory options for *all gas pipeline facilities* had to comply with the rulemaking mandate in Section 113, even though that mandate does not apply to onshore gas gathering lines in Class 1 locations, including Type C gathering lines. The only alternative regulatory options identified in the PRIA involve distribution lines and eliminating a proposed exception for compressor stations. There is no indication that PHMSA considered any of the various regulatory options available in developing the proposed LDAR requirements for Type C lines, *e.g.*, extending the current leak detection and repair requirements to all Type C lines; establishing new minimum leak detection and repair standards for all Type C lines, but omitting the proposed ALDP requirements; establishing new minimum leak detection and repair standards for all Type C lines, but only applying the ALDP requirements to larger diameter or higher risk segments, *etc.*

The Agency failed to adequately identify the costs and benefits associated with the proposed LDAR requirements for Type C lines as well. GPA and API advised PHMSA during the public meeting on Section 113 and Section 114 that gas gathering lines are not subject to public-utility-style economic regulation, and that operators cannot recover increased compliance costs through traditional ratemaking proceedings or special cost recovery mechanisms. The Agency did not consider that important aspect of the problem at all in analyzing the costs of the gas gathering provisions in the Proposed Rule,[38] even though PHMSA has previously acknowledged that the ability of public utilities to recover costs through general and specific ratemaking mechanisms is a significant economic consideration from a pipeline safety perspective.[39] PHMSA also failed to quantify any of the safety benefits associated with the proposed LDAR requirements. Setting aside the fact that the Agency is charged with prescribing *safety standards* for pipeline facilities,[40] the incremental safety benefits of detecting and repairing the extremely small leaks that are subject to the Proposed Rule—which do not have a meaningful impact on reducing methane emissions—are clearly relevant in determining whether the costs are justified.[41] The safety benefits of applying the LDAR requirements to Type C gathering lines that

[38] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("Normally, an agency rule would be arbitrary and capricious if the agency has . . . entirely failed to consider an important aspect of the problem[.]").

[39] PHMSA, White Paper on State Pipeline Infrastructure Replacement Programs (Dec. 2011), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/PHMSA%20111011-002%20NARUC.pdf. *See also GPA Midstream Ass'n*, 67 F.4th at 1199-1200 ("The operators point to several other differences between gathering and transmission lines. . . They also tell us gas transmission operators behave differently because they are price-regulated public utilities, while the gas gathering sector relies upon market prices to recover costs. Although we cannot fully evaluate the importance of these asserted differences precisely because the agency failed to develop an adequate administrative record in time for comment, they surely seem relevant to the agency's decision making, and at a minimum show the agency's procedural error was prejudicial.").

[40] 49 U.S.C. § 60102(a)(2).

[41] *See* Highwood Emissions Management, Technical Report: PHMSA Methane Detection Requirements Analysis, Evaluation of PHMSA's proposed monitoring technology requirements at 2 (July 27, 2023) (recommending that

do not have any buildings intended for human occupancy or other impacted sites within the potential impact circle are clearly relevant for the same reason.

The technical data and other information that the Agency used in developing the Proposed Rule and conducting the risk assessment is likewise inadequate. PHMSA relied almost entirely on assumptions in evaluating the costs, benefits, and other impacts of the proposed LDAR requirements for Type C gathering lines. The Agency not only failed in many cases to provide the explanations needed to understand the basis for those assumptions, but declined to use the current data and other information that Type C gathering line operators are now providing to PHMSA in incident, annual, and safety-related condition reports. Having recently invoked the information collection authority in 49 U.S.C. § 60117(c) to require gathering line operators to provide these reports, the Agency cannot simply ignore the data and other information submitted in proposing new regulations for more than 90,000 miles of Type C lines.[42] Nor is PHMSA's promise to consider the reports during the subsequent phases of the rulemaking process an adequate substitute for considering the data and information in conducting the risk assessment and making the results available for public review, particularly when the Agency is not acting pursuant to a congressional mandate or in response to a statutory deadline for issuing LDAR regulations for Type C lines.[43]

In summary, the Agency did not satisfy the requirements in Section 60102(b)(3) in conducting the risk assessment for the proposed LDAR requirements for Type C gathering lines. PHMSA failed to consider any non-regulatory options and limited its consideration of the regulatory options based on an erroneous legal assumption. The Agency also failed to reasonably identify the costs and benefits and relied on inadequate technical data and information. These are

PHMSA "consider the small benefit of detecting and repairing small leaks that are not impactful for emissions mitigation," and that "[f]ocusing on large sources can bring substantial emissions reductions while ensuring efficient use of resources") (Highwood Report) (attached hereto); *GPA Midstream Ass'n*, 67 F.4th at 1200 ("The risk assessment does not quantify any of the benefits of the standard. This is troubling enough, as a reasoned decision would explain why any unquantified benefits cannot reasonably be quantified. . . . Quantifying benefits always requires making projections, so it is no answer to say 'a detailed projection of avoided incidents and avoided costs is not available.' . . . Without quantified benefits to compare against costs, it is not apparent just how the agency went about weighing the benefits against the costs.").

[42] PHMSA specifically invoked the information collection authority in 49 U.S.C. § 60117(c) in responding to commenters who questioned the new reporting requirements for onshore gas gathering lines in Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, 86 Fed. Reg. at 63,275 (stating the "Section 60117(b) [sic] of Federal Pipeline Safety Law specifically authorizes the Secretary to 'require owners and operators of gathering lines to provide the Secretary information pertinent to the Secretary's ability to make a determination as to whether and to what extent to regulate gathering lines,'" that "Congress made no distinction between 'gathering lines' and 'regulated gathering lines' for reporting purposes," and that collecting "information on all gathering lines that would enable PHMSA to make informed judgments about the need for, and scope, of potential regulation").

[43] The Agency relies on the final regulatory impact analysis (2021 FRIA) prepared for the November 2021 gas gathering rule as a source for several aspects of the risk assessment. The 2021 FRIA relied heavily on information that IPAA purportedly provided to the Agency during a 2006 rulemaking proceeding. Final Regulatory Impact Analysis (Nov. 2021), https://www.regulations.gov/document/PHMSA-2011-0023-0488. PHMSA recently acknowledged that the historical data submitted by IPAA is no longer available for review. PHMSA, Letter Tristan H. Brown, Deputy Administrator to Mathew Hite, GPA Midstream (Apr. 15, 2022) https://www.regulations.gov/document/PHMSA-2011-0023-0507. The Agency cannot prepare an adequate risk assessment by relying on outdated, and otherwise unavailable, data from a years-old rulemaking proceeding. *See*, Appeal of Decision Denying Petition for Reconsideration at 7-8, PHMSA-2011-0023, https://www.regulations.gov/document/PHMSA-2011-0023-0509.

serious errors that must be corrected before the proposed LDAR requirements for Type C gathering lines can be advanced to the next phase of rulemaking process. Otherwise, the public will be deprived of the opportunity to provide meaningful comment and the GPAC will be prohibited from performing its peer review function.[44]

b. The Proposed Reporting Requirements for Large-Volume Gas Releases Should Be Clarified.

PHMSA proposes to amend 49 C.F.R. Part 191 to require operators to submit reports on large-volume gas releases.[45] A large-volume gas release would be defined as "an intentional or unintentional release of 1 million cubic feet or more of gas from a gas pipeline facility as that term is defined in § 192.3."[46] A report would need to be submitted "within 30 days after detection of a large-volume gas release,'" unless "an incident report has already been submitted under [49 C.F.R. Part 191] for the same event and the release volume identified in the incident report is within 10 percent of the total release volume on cessation of the release."[47] The Gas Gathering Industry Commenters agree that requiring gathering line operators to submit reports on large-volume gas releases is reasonable, provided the Agency clarifies certain aspects of the Proposed Rule.

The proposed definition of large-volume gas release does not specify whether an intentional flaring event would constitute a release. The proposed requirements for minimizing emissions from gas blowdowns in § 192.770 imply that flaring does not qualify as a release of gas, as flaring is listed as an alternative to blowdown and venting in that proposal. PHMSA should clarify the definition of a large-volume gas release in the final rule to state that a release of gas does not include gas that is burned through flaring or consumed as fuel.[48] Making that clarification will provide operators with greater certainty in implementing the proposed requirements.

The Agency should also eliminate the proposed 10-percent-incident-reporting threshold from the exception to an operator's obligation to submit a large-volume gas release report. PHMSA already requires operators to submit supplemental incident reports as new information becomes available, and any changes in the total amount of gas released during an incident will be reflected in these supplemental reports. There is no need to condition the proposed exception for large-volume gas reporting on the proposed 10 percent-of-the-total-volume-of-gas-released included in an incident report threshold. That condition introduces unnecessary complexity into what should be a straightforward process for submitting supplemental incident reports.

Finally, the Agency should provide an exception from the large-volume gas release reporting requirements for events that are permitted by or reported to EPA or state programs acting pursuant to authority delegated by EPA. There is no need to require duplicative reporting of the same event to PHMSA if another federal or state agency is already receiving the pertinent information.

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[44] *GPA Midstream Ass'n*, 67 F.4th at 1197.
[45] Proposed Rule, 88 Fed. Reg. at 31,893.
[46] *Id.* at 31,972
[47] *Id*.
[48] EPA and other federal agencies already collect emissions information on flaring and fuel consumption, including through the Greenhouse Gas Reporting Program (GHGRP), which provides further support for the conclusion that additional reporting to the Agency is unnecessary.

c. The Proposal to Require Gathering Line Operators to Participate in NPMS is Unlawful, Unnecessary, and Otherwise Unsupported.

The Pipeline Safety Act prohibits the Agency from adopting the proposal to require gathering line operators to participate in the NPMS.[49] PHMSA's authorization to administer the NPMS program is codified at 49 U.S.C § 60132. Subsection (a) of that provision states, in relevant part, that "the operator of a pipeline facility (*except distribution lines and gathering lines*)" shall submit geospatial data and other information to the NPMS.[50] The exception for distribution and gathering lines in Section 60132(a) dates back to the original, voluntary digital pipeline mapping program that PHMSA created in the late 1990s.[51] The Agency excluded "gas service lines, gas distribution lines, gathering lines, flow lines, or spur lines" from that program,[52] and Congress carried that exclusion forward by including the exception for distribution and gathering lines in adding Section 60132(a) to the Pipeline Safety Act in the Pipeline Safety and Improvement Act of 2002 (2002 Act).[53] The original language of the exception from the 2002 Act remains codified at § 60132(a) and has not been altered in any of the four subsequent reauthorizations of the Pipeline Safety Act.[54]

PHMSA "must give effect to the unambiguously expressed intent of Congress" in administering the Pipeline Safety Act.[55] The ordinary meaning of "except" is "to take or leave out from a number or a whole[,]" *i.e.*, to "exclude",[56] and the text, structure, and history of the NPMS provision confirm that Congress used the word "except" in the exclusionary sense in § 60132(a), *i.e.*, that Congress intended "to take" distribution lines and gathering lines "out" from the broader "whole" of pipeline facilities subject to the NPMS program requirements.[57] That is evident from

[49] Proposed Rule, 88 Fed. Reg. at 31,945 - 947, 31,972.
[50] 49 U.S.C. § 60132(a). None of the other provisions in the NPMS statute affects the language of the exception for gathering lines in subsection (a). Subsection (b) requires "[a] person providing information under subsection (a)" to update that information as necessary "to reflect changes . . . and as otherwise required by the Secretary." *Id.* § 60132(b). Subsection (c) authorizes the Secretary to provide NPMS-related technical assistance to state and local governments, and subsection (d) requires the Secretary to maintain and update biennially a map depicting high consequence areas in the NPMS. *Id.* § 60132(c)-(d). Finally, subsection (e) requires the Secretary to develop a public awareness program for the NPMS, and subsection (f) includes provision relating to the disclosure of information. *Id.* § 60132(e)-(f).
[51] Pipeline Safety: National Pipeline Mapping System, 63 Fed. Reg. 36,030, 36,031 (July 1, 1998) ("DOT strongly urges all natural gas transmission and hazardous liquid pipeline and liquefied natural gas facility operators to attend one of these meetings and to voluntarily provide mapping data for inclusion in the national pipeline mapping system").
[52] *Id.*
[53] Pipeline Safety and Improvement Act of 2002, Pub. L. 107–355, § 15, 116 Stat. 2985, 3005-06 (2002) (codified at 49 U.S.C. § 60132).
[54] Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, Pub. L. 109-468, 120 Stat. 3486 (2006); Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Pub. L. 112-90, 125 Stat. 1904 (2012); Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016, Pub. L. 114-183, 130 Stat. 514 (2016); Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020, Consolidated Appropriations Act, 2021, Division R, Pub. L. 116-260 (2020), 134 Stat. 2210.
[55] *Chevron, U.S.A., Inc. v. Nat. Resources Defense Council, Inc.*, 467 U.S. 837, 842-43 (June 25, 1984).
[56] *Except*, Merriam-Webster Dictionary, https://www.merriam-webster.com/dictionary/except?src=search-dict-box.
[57] The word "except" appears 23 times in Chapter 601 and one time in Chapter 603. In addition to 49 U.S.C. § 60132(a)(1), there at least six other instances where "except" is used in the exclusionary sense, and in four of those instances Congress embedded that exception in a parenthetical reference that followed the more expansive term. *See* 49 U.S.C. §§ 60101(a)(12) ("liquefied natural gas accident' means a release, burning or explosion . . . except a release

the language that Congress used in the parenthetical reference in § 60132(a) and draws further support from the legislative and regulatory history, which shows that PHMSA excluded gathering and distribution lines from the original voluntary digital mapping program, and that Congress codified that exclusion in authorizing the NPMS program in the 2002 Act.

PHMSA suggests in the NPRM that 49 U.S.C. § 60117(c) authorizes the proposed requirement to make gathering line operators participate in the NPMS. Section 60117(c) generally provides the Agency with the authority to require operators to provide information for compliance purposes, *i.e.*, "to decide whether a person owning or operating a pipeline facility is complying with this chapter and standards prescribed or orders issued under this chapter."[58] Section 60117(c) further provides that the Agency "may require owners and operators of gathering lines to provide [PHMSA] information pertinent to [PHMSA's] ability to make a determination as to whether and to what extent to regulate gathering lines."[59] As explained below, PHMSA's position that Section 60117(c) authorizes the Agency to require gathering line operators to participate in the NPMS is baseless.

It is well settled that "an agency may not circumvent specific statutory limits on its actions by relying on separate, general rulemaking authority."[60] Congress enacted a specific and comprehensive statute for the NPMS program in the 2002 Act, articulating the type of information that operators had to provide to the Agency, allowing PHMSA to require operators to update that information, and authorizing the Agency to provide technical assistance to State and local officials in using the NPMS data for emergency response purposes. As part of enacting that detailed statutory scheme, Congress also decided to provide an express exception for gathering lines (and distribution lines). Congress has left that exception in place since the 2002 Act, despite making other changes to Section 60132 in the Pipeline Safety, Regulatory Certainty, and Job Creation of 2011, and PHMSA cannot use the general information collection authority in Section 60117(c) to rewrite the NPMS statute that Congress enacted decades after the fact.[61]

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burning or explosion that . . . does not pose a threat"), (a)(16) ("'new liquefied natural gas pipeline facility' means a liquefied natural gas pipeline facility except an existing liquefied natural gas pipeline facility"), (a)(22)(B)(i) (transporting hazardous liquid does not include "gathering lines (except regulated gathering lines) in a rural area"), 60102(h)(i) ("The Secretary shall prescribe regulations requiring each operator of a pipeline facility (except a master meter"), 60103(g) ("This section does not preclude applying a standard prescribed under section 60102 of this title to a gas pipeline facility (except a liquefied natural gas pipeline facility)"), 60109(a)(1)(A) ("each gas pipeline facility (except a natural gas distribution line) located in a high-density population area").

[58] 49 U.S.C. § 60117(c).

[59] *Id.*

[60] *Air Alliance Houston v. EPA*, 906 F.3d 1049, 1053, 1061–1066 (D.C. Cir. 2018); *see also RadLAX Gateway Hotel, LLC v. Amalgamated Bank*, 566 U.S. 639, 645–647 (2012); *American Petroleum Inst. v. EPA*, 706 F.3d 474, 479–480 (D.C. Cir. 2013) ("a broad programmatic objective cannot trump specific instructions"); *Michigan v. Envt'l Prot. Agency*, 268 F.3d 1075, 1084 (D.C. Cir. 2001) ("EPA cannot rely on its general authority to make rules necessary to carry out its functions when a specific statutory directive defines the relevant functions of EPA in a particular area." (citation omitted)); *Asiana Airlines v. FAA*, 134 F.3d 393, 401–403 (D.C. Cir. 1998) (same); *American Petroleum Inst. v. EPA*, 52 F.3d 1113, 1119 (D.C. Cir. 1995) ("the general grant of rulemaking power to EPA cannot trump specific portions of the CAA").

[61] The general information collection authority in Section 60117(c) predates the enactment of the NPMS statute in Section 60132, further demonstrating the unreasonableness of PHMSA's position. If Congress intended the Agency to use the authority in Section 60117(c) to require NPMS participation, it would not have enacted Section 60132 in the first instance.

Nor do the reasons offered by the Agency for requiring gathering line operators to participate in the NPMS support an exercise of the general information collection authority in Section 60117(c). The information that operators provide to the NPMS program is not used for general compliance purposes. Operators provide PHMSA with that kind of information in responding to requests for specific information or in the various reports that must be submitted under 49 C.F.R. Part 191. Indeed, the Agency recently used the authority in Section 60117(c) to require gathering line operators to submit new Part 191 reports for the express purpose of deciding whether to establish new regulations for gathering lines in future rulemaking proceedings.[62] PHMSA said nothing in the final rule about using the general information collection authority in Section 60117(c) to require gathering line operators to participate in the NPMS. To the contrary, the Agency added an express exception for gathering lines to the NPMS regulation in that final rule.[63]

Even if PHMSA had the legal authority to require gathering line operators to participate in the NPMS, the record does not provide an adequate basis for pursuing that proposal. Most gathering line operators already provide appropriate pipeline location information to the authorities that administer state damage prevention programs, and these authorities do not generally require information to be submitted in a geographic information system format or with the level of detail that PHMSA requires for the NPMS program. Imposing an additional burden on gathering line operators to provide geospatial data solely for informational purposes is unreasonable, particularly given the effectiveness that state damage prevention programs have shown in protecting legitimate risks to public safety, and the specific informational interests of the other stakeholders that the Agency identifies in the Proposed Rule do not change that analysis.

d. The Proposed Definition of a Leak or Hazardous Leak Departs Significantly from Established Precedent and is Not Supported by the Required Risk Assessment Information.

PHMSA proposes to amend 49 C.F.R. § 192.3 by defining a "[l]eak or hazardous leak . . . , for the purposes of all subparts of part 192 except § 192.12(d) and subparts O and P," 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."[64] In describing the rationale for the proposed definition, the Agency states that "all 'leaks' are necessarily hazardous to the environment, and even a small leak can be hazardous to public safety, especially if it is allowed to continue indefinitely without repair and potentially degrade into a more serious leak or incident."[65] PHMSA further states that the proposed definition of leak or hazardous leak would only impose "de minimis" compliance burdens, "because (1) a reasonably prudent operator would already employ practices and procedures sensitive to environmental harms

[62] Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, 86 Fed. Reg. 63,266 (codified at 49 C.F.R. pt. 191, 192)
[63] 49 C.F.R. § 191.29(c).
[64] Proposed Rule, 88 Fed. Reg. at 31,972.
[65] *Id.* at 31,953.

from leaks in their activities, and (2) the mechanism for pertinent public safety and environmental harms (i.e., the release of gas from a pipeline from a leak) is identical."[66]

Contrary to the Agency's assertions, the proposed definition of "leak or hazardous leak" departs significantly from decades of well-established precedent and industry practice. The regulations in Part 192 have long recognized that not all leaks are hazardous. As PHMSA itself acknowledged in describing its regulations in an August 1972 letter to a member of Congress, "Which leaks are 'hazardous,' which leaks make a pipeline 'unsafe,' and whether a repair has been done 'promptly,' depends upon the nature of the operation and local conditions. The nature and size of the leak, its location, and the danger to the public are among the factors that must be considered by the operator."[67]

The Gas Piping Technology Committee (GPTC) has long recognized that not all leaks are hazardous as well. The GPTC guidance for Grade 2 and Grade 3 leaks acknowledges that leaks can be non-hazardous at the time of detection, and the Grade 3 guidance acknowledges that a leak can remain non-hazardous into the future. Congress recognized in Section 113 that a pipe can have "a leak so small that it poses no potential hazard,"[68] and EPA, the federal agency charged with administering the provisions in the Clean Air Act, has recognized that not all leaks are hazardous to the environment in its LDAR regulations.[69] PHMSA even concedes, by way of the exceptions provided for the underground gas storage program and transmission and distribution integrity management programs, that the proposed definition of "leak or hazardous leak" is not appropriate to apply throughout the Part 192 regulations.

The proposed definition of "leak or hazardous leak" also conflicts with the common understanding of those terms. When used as a noun, "leak" ordinarily means "a crack or hole that usually by mistake admits or lets escape", "something that permits the admission or escape of something else usually with prejudicial effect", or "the act, process, or an instance of leaking."[70] "Hazardous" is an adjective that, in relevant part, ordinarily means "involving or exposing one to risk (as of loss or harm)," *e.g.*, "a hazardous occupation" or "disposing of hazardous waste".[71] While the pipeline safety regulations often involve highly specialized or technical terms, no ordinary person would assume that a "leak" is the same thing as a "hazardous leak", especially as

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[66] PRIA at 16.
[67] PHMSA Letter of Interpretation to the Honorable William D. Hathaway, PI-72-0109 (Aug. 4, 1972).
[68] 49 U.S.C. § 60102(q)(2)(B)(ii).
[69] Rather than treating all leaks as hazardous to the environment, EPA has relied on a variety of factors, including cost effectiveness evaluations, examinations of leak definitions under similar state and federal statutes, experience with various leak definitions required by consent decrees, and the ability to repair detected leaks, among others, in developing its LDAR regulations. *See* Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. 52,738, 52,764-66 (Aug. 23, 2011) (evaluating potential leak definitions of 10,000 ppm and 500 ppm based on cost effectiveness for Subpart OOOO); Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry; Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, 71 Fed. Reg. 65,302, 65,305 (Nov. 7, 2006) (establishing 500 ppm leak definition under Subpart VV based on other regulatory leak definitions and experience under consent decrees); Hazardous Wast Treatment, Storage, and Disposal Facilities; Air Emission Standards for Volatile Organics Control, 52 Fed. Reg. 3,748, 3,757-58 (Feb. 5, 1987) (10,000 ppm leak definition informed by control technologies, the frequency of monitoring, and the ability to repair a leak to below 10,000 ppm).
[70] *Leak*, Merriam-Webster Dictionary, https://www.merriam-webster.com/dictionary/leak.
[71] *Hazardous*, Merriam-Webster Dictionary, https://www.merriam-webster.com/dictionary/hazardous

the purpose of an adjective is to modify or describe something in particular about a noun. Suggesting otherwise invites an *Alice in Wonderland* approach to defining the terms used in PHMSA's regulations.[72]

The Agency clearly erred in failing to conduct a risk assessment for the proposed definition of "leak or hazardous leak". PHMSA stated in the PRIA that the proposed definition would impose a de minis compliance burden, but that is obviously not the case. The Agency's definition departs significantly from decades of well-established regulatory precedent and industry practice and would impose significant compliance burdens on the gas pipeline industry, particularly when applied to the proposed LDAR requirements. The Agency must conduct a risk assessment and make the results available for public comment and peer review by the GPAC to advance such a proposal. In conducting that risk assessment, the Agency should consider appropriate regulatory and non-regulatory options and follow the longstanding practice of defining the terms "leak" and "hazardous leak" separately, so that leak detection and repair resources are more effectively used. Vague words, such as "uncontrolled", should be omitted and any definitions proposed should make clear that releases which occur as part of normal pipeline operations are not leaks. Catchall phrases, like "existing, probable, or future", should also be omitted to ensure that any definitions proposed can be fairly and consistently applied throughout the Part 192 regulations.

e. The Proposed Definition of Confined Space Should be Aligned with Definition Used by the Occupational Safety and Health Administration.

PHMSA proposes to amend 49 C.F.R. § 192.3 by defining a "confined space" as "any subsurface structure, other than a building, of sufficient size to accommodate a person, and in which gas could accumulate or migrate. These include, vaults, certain tunnels, catch basins, and manholes."[73] The proposed definition does not align with the definition of "confined space" used by the Occupational Safety and Health Administration (OSHA).[74] OSHA defines a "confined space" in its regulations as "a space that: (1) Is large enough and so configured that an employee can bodily enter and perform assigned work; and (2) Has limited or restricted means for entry or exit (for example, tanks, vessels, silos, storage bins, hoppers, vaults, and pits are spaces that may have limited means of entry.); and (3) Is not designed for continuous employee occupancy."[75] To avoid creating unnecessary confusion, the Gas Gathering Industry Commenters urge PHMSA to align its definition of "confined space" with the OSHA definition in the final rule.

f. The Proposal to Require a Manual of Written Procedures for Type B and Type C Gathering Lines Must Be Revised.

PHMSA proposes to amend 49 C.F.R. § 192.9(d) and (e) to clarify that operators of Type B and Type C gathering lines must have a written manual of procedures for conducting certain operations, maintenance, and emergency response activities.[76] The Agency believes these

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[72] *United States v. Meyer*, 50 F.4th 23, 28, n.2 (11th Cir. 2022) ("'When I use a word,' Humpty Dumpty said, in rather a scornful tone, 'it means just what I choose it to mean – neither more nor less.'") (quoting Lewis Carroll, Alice's Adventures in Wonderland & Through the Looking Glass 124–25 (New York: The MacMillan Company 1897)).
[73] Proposed Rule, 88 Fed. Reg. at 31,955, 31,972.
[74] 29 C.F.R. § 1910.146(b).
[75] *Id.*
[76] Proposed Rule, 88 Fed. Reg. at 31,972.

clarifications are necessary to dispel stakeholder confusion and codify certain provisions in Section 114 of the 2020 PIPES Act.[77] The Gas Gathering Industry Commenters are not opposed to clarifying the obligation of Type B and Type C gathering line operators to have a manual of written procedures, but do not support the proposed amendments to 49 C.F.R. § 192.9(d) and (e) for the following reasons.

PHMSA's assertion that Section 114 is a "self-executing mandate" that applies to Type C gathering lines is incorrect.[78] The uncodified provision in Section 114 did not apply to Type C gathering lines, which were not jurisdictional on December 27, 2020, the date when that provision went into effect, or on December 27, 2021, the date when operators of gas pipeline facilities had to update their inspection and maintenance plans to address the new factors that Congress added to 49 U.S.C. § 60108(a)(2)(D)-(E). Moreover, the new factors that Congress added in the codified portion of Section 114 only apply to the Agency and state pipeline safety authorities that are responsible for reviewing inspection and maintenance plans. None of those factors applies directly to an operator of a gas pipeline facility (as demonstrated by Congress' decision to enact the separate, uncodified mandate in Section 114 directing operators jurisdictional gas pipeline facilities to update their inspection and maintenance plans by December 27, 2021). PHMSA also mischaracterizes the language in Section 114 in the Proposed Rule by attempting to impose express obligations that are not present in the statutory text. Nothing in Section 114, for example, says that inspection and maintenance plans must "specifically address intentional venting during blowdown or other scheduled maintenance activities".[79]

The risk assessment fails to account for the costs, benefits, and other impacts of requiring Type C onshore gas gathering lines to "remediat[e] or replac[e] pipelines known to leak based on their material, design, or past operating and maintenance history."[80] As PHMSA acknowledged in a 2011 white paper to the National Association of Regulatory Utility Commissioners (NARUC), many state authorities have special programs in place that allow gas public utilities to recover the costs of remediating and replacing pipeline infrastructure on an expedited basis.[81] Gathering line operators, which are not subject to public utility regulation, do not have access to these cost recovery programs.[82] The PRIA does not consider that important aspect of the problem at all,[83] even though GPA and API specifically raised the concern during the 2021 public meeting on the implementation of Section 114.[84]

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[77] *Id.* at 31,956.

[78] *Sec'y of Labor v. Nat'l Cement Co. of Cal., Inc.*, 494 F.3d 1066, 1073 (D.C. Cir. 2007) (citing *Peter Pan Bus Lines, Inc. v. Fed. Motor Carrier Safety Admin.*, 471 F.3d 1350, 1354 (D.C. Cir. 2006) ("[D]eference to an agency's interpretation of a statute is not appropriate when the agency wrongly believes that interpretation is compelled by Congress." (internal quotation marks omitted)).

[79] PRIA at 5.

[80] Proposed Rule, 88 Fed. Reg. at 31,974.

[81] White Paper on State Pipeline Infrastructure Replacement Programs (Dec. 2011), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/PHMSA%20111011-002%20NARUC.pdf.

[82] Kurt L. Krieger, Gathering and Transporting Marcellus and Utica Shale Natural Gas to the Market and the Regulation of Midstream Pipeline Companies - The Case for a Uniform Federal and State Definition of "Gathering" in the Context of Economic and Siting Regulation, Texas Wesleyan Law Review (Oct. 1, 2012).

[83] *Motor Vehicle Mfrs. Ass'n of U.S., Inc.*, 463 U.S. at 43 ("Normally, an agency rule would be arbitrary and capricious if the agency has . . . entirely failed to consider an important aspect of the problem[.]").

[84] *GPA Midstream Ass'n*, 67 F.4th at 1199-1200 ("The operators point to several other differences between gathering and transmission lines. . . . They also tell us gas transmission operators behave differently because they are price-

The risk assessment does not identify the benefits of requiring operators of Type C onshore gas gathering lines to remediate or replace historically leak-prone pipelines either. Section 114 lists "cast iron, unprotected steel, wrought iron, and historic plastics with known issues" as the types of pipeline materials that are prone to leak. PHMSA listed the same materials in describing the kinds of high-risk pipeline infrastructure that warranted accelerated repair or remediation in the 2011 NARUC white paper.[85] While gas distribution operators used these materials during certain historical periods, there is nothing in the record about the use of these materials in constructing Type C onshore gas gathering lines. Nor does the Proposed Rule specify the circumstances where the design or past operating and maintenance history of a pipeline would warrant replacement or remediation or identify the costs and benefits associated with requiring replacement or remediation in those circumstances.

The risk assessment does not account for the full extent of the proposed changes to the written procedures for Type B and Type C gathering lines. The Proposed Rule would require operators to have a written manual of procedures for each of the elements in 49 C.F.R. § 192.605, subject to certain limited exceptions.[86] That proposal goes well beyond the discrete list of operations, maintenance, and emergency response requirements that apply to Type B and Type C gathering line operators under the current regulations. Nevertheless, PHMSA assumed in the PRIA that the Proposed Rule only requires operators of Type B and Type C gathering lines to have a manual of written procedures for the specific operations, maintenance, and emergency response requirements listed in 49 C.F.R. § 192.9(d) and (e). To comply with the risk assessment requirements in the Pipeline Safety Act, the Agency must revise the language to align with the assumptions used in the PRIA, *i.e.*, by eliminating the proposed reference to 49 C.F.R. § 192.605 and limiting the obligation for written procedures to the provisions expressly referenced in § 192.9(d) and (e).

g. The Proposal to Amend the 90-Day Prior Notification and No-Objection Process Should Be Reconsidered Given the Significant Concerns with the Other Provisions in the Proposed Rule.

PHMSA proposes to add several new regulations to the 90-day prior notice and no-objection process in 49 C.F.R. § 192.18(c).[87] As discussed elsewhere in these comments, the Gas Gathering Industry Commenters have significant concerns with several of those regulations, particularly the LDAR requirements. The Gas Gathering Industry Commenters are also concerned that PHMSA is trying to use the 90-day prior notice and no-objection process in § 192.18(c) to circumvent its obligation to comply with the rulemaking requirements in the Pipeline Safety Act in proposing new regulations. As the D.C. Circuit recently explained in *GPA Midstream Ass'n*,

regulated public utilities, while the gas gathering sector relies upon market prices to recover costs. Although we cannot fully evaluate the importance of these asserted differences precisely because the agency failed to develop an adequate administrative record in time for comment, they surely seem relevant to the agency's decision making, and at a minimum show the agency's procedural error was prejudicial.").

85 White Paper on State Pipeline Infrastructure Replacement Programs (Dec. 2011), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/PHMSA%20111011-002%20NARUC.pdf.

86 Proposed Rule, 88 Fed. Reg. at 31,952, 31,974.

87 *Id.* at 31,957, 31,973.

the Agency cannot force operators to seek relief under § 192.18 from a regulation that is arbitrary and capricious or otherwise unlawful.[88]

h. The Proposal to Amend the Requirements for the Design and Configuration of Pressure Relief and Limiting Devices Should Be Clarified.

PHMSA proposes to amend the requirements in 49 C.F.R. § 192.199 for the design and configuration of pressure relief and limiting devices to require operators to minimize unnecessary releases of gas by preparing a "documented engineering analysis" that addresses certain criteria.[89] One of the criteria that operators must address in that analysis is the "inclu[sion] upstream and downstream isolation valves to facilitate testing and maintenance."[90] The Gas Gathering Industry Commenters are not opposed to the proposed amendment, provided PHMSA makes the following clarifications.

The Agency should either clarify or eliminate the phrase "documented engineering analysis". That phrase is not defined in the Proposed Rule or subject to a common understanding within the pipeline industry. If the intent is to require operators to maintain records or documentation for compliance purposes, PHMSA can include language to that effect in the final rule. The Agency should not use a phrase, such as "documented engineering analysis," that is otherwise undefined.

PHMSA should also clarify the provision relating to upstream and downstream isolation valves. The proposed language does not indicate whether downstream pressure safety valves (PSV) must be installed at the inlet or after the discharge of the relief device. A requirement to install an isolation valve on the discharge side of a relief valve would introduce safety risks associated with inadvertent closures that could block the PSV. Such a requirement is also unnecessary as relief devices are regularly isolated by a root valve located beneath the PSV. A requirement to isolate the pipeline upstream and downstream of the relief device inlet would cause more gas to be blown down or vented every time PSV maintenance is conducted. Replacing the upstream and downstream isolation valve requirement with language indicating the relief device must be isolatable to facilitate testing and maintenance would address these concerns.

i. The Proposed Definition of Failure is Not Supported by a Risk Assessment and Should Be Revised.

PHMSA proposes to add a definition of "failure" to the requirements in 49 C.F.R. § 192.617.[91] Section 192.617 currently requires, in relevant part, that operators "establish and follow procedures for investigating and analyzing failures and incidents as defined in § 191.3" and "develop, implement, and incorporate lessons learned from a post-failure or incident review."[92]

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[88] *GPA Midstream Ass'n*, 67 F.4th at 1199.
[89] Proposed Rule, 88 Fed. Reg. at 31,951, 31,973.
[90] *Id.* at 31,973.
[91] *Id.* at 31,951, 31,974.
[92] 49 C.F.R. § 192.617(a)-(b). Section 192.617 further requires that operators take additional steps in analyzing failure or incidents that involve the closure of rupture-mitigation valves (RMV) on onshore gas transmission lines. *Id.* § 192.617(c)-(d). The U.S. Court of Appeals vacated the RMV requirements in § 192.617 that apply to Type A gathering lines in *GPA Midstream Ass'n*, 67 F.4th at 1201-1202, and PHMSA recently amended 49 C.F.R. § 192.9(c)

The Agency proposes to amend these requirements by adding a provision that defines the term "failure" as "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."[93] PHMSA states that its proposed definition of a "failure" is based on a comparable definition in the ASME B31.8.[94]

The definition of "failure" in the Proposed Rule deviates from the ASME B31.8 definition in at least one critical respect. The ASME B31.8 definition is limited to circumstances where a pipeline "has deteriorated seriously**,** to the point that it has become unreliable or unsafe for continued use."[95] PHMSA's proposed definition omits the serious deterioration concept, resulting in an overly broad meaning of the term "failure," particularly when applied to the various components, devices, and equipment on pipelines that are regularly replaced due to inoperability. Each of these routine replacements would trigger a full failure investigation under the proposed definition. To avoid that unreasonable result and maintain consistency with the ASME B31.8 definition, PHMSA must incorporate the "serious deterioration" concept into the definition of failure in the final rule. The Agency should also exclude from the definition of failure instances where the inoperability of components, devices, and equipment does not otherwise impact the integrity or continued safety of the pipeline.

The PRIA states that the Agency assumed that the definition in the Proposed Rule was consistent with existing industry standards and would not result in any additional compliance costs or benefits. To satisfy the requirements in 49 U.S.C. § 60102(b)(3), PHMSA must either revise the definition of a failure in the final rule to align with the provisions in ASME B31.8 and the assumption used in the PRIA or conduct a new risk assessment of the definition in the Proposed Rule and make the results of that risk assessment available to the public for comment. Anything less would be a violation of the rulemaking requirements in the Pipeline Safety Act.

j. The Proposed Exception for EPA-Regulated Compressor Stations Should be Clarified.

PHMSA is proposing to add the following exception from the requirements for conducting ROW patrols and leak surveys, grading and repairing leaks, implementing advanced leak detection programs, and the qualification of leak survey personnel:

> for a compressor station on a gas transmission or gathering pipeline if:
> (1) The facility is subject to methane emission monitoring and repair requirements under either:
> (i) 40 CFR part 60, subparts OOOOa or OOOOb; or
> (ii) an EPA-approved State plan or Federal plan which includes relevant standards at least as stringent as EPA's finalized emissions guidelines in 40 CFR part 60, subpart OOOOc;

to reflect that decision, Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards: Technical Corrections, 88 Fed. Reg. 50,056 (Aug. 1, 2023).

[93] Proposed Rule, 88 Fed. Reg. at 31,958, 31,974.

[94] *Id.* at 31,951.

[95] *Id.*

> (2) The facility is within the first block valve entering or exiting the compressor station covered by the emergency shutdown system as required in § 192.167 for station isolation from the pipeline; and
> (3) Repair records are maintained for the life of the facility in accordance with § 192.760(i).[96]

The Gas Gathering Industry Commenters support the proposed exception for compressor station facilities on gathering lines that are subject to EPA's methane emission monitoring and repair requirements in Subpart OOOOa and, if finalized, Subparts OOOOb and OOOOc. EPA's comprehensive regulations render compliance with PHMSA's requirements for ROW patrolling, leak surveying, leak grading and repairing, ALDP, and qualification of leak survey personnel unnecessary.

However, the Gas Gathering Industry Commenters urge PHMSA to clarify the exception in 192.703(d)(1)(ii) to state "an EPA Federal plan or EPA-approved State plan implementing the emissions guidelines in 40 CFR 60, subpart OOOOc." That clarification is necessary because an EPA-approved state plan is allowed to deviate from the emissions guidelines based on factors such as remaining useful life. The Gas Gathering Industry Commenters also urge the Agency to remove the additional recordkeeping provision from the exception. EPA is responsible for prescribing and enforcing recordkeeping requirements for the regulations referenced in the exception. PHMSA has no legal authority to enforce EPA's regulations, and there is no reason for the Agency to impose a separate requirement that these records be maintained to qualify for the exception.

Finally, the Agency should ensure that the applicability of the exception aligns in all respects with the scope of EPA's regulations. There is no reason for PHMSA to apply its LDAR regulations to facilities at compressor stations that are subject to EPA's methane emission monitoring and reporting requirements. Doing so would only create unnecessary overlap and jurisdictional conflicts without promoting public safety or the protection of the environment.

k. The Risk Assessment for the Proposed Increase in the Frequency of the Patrolling Requirements is Inadequate, and the Proposal is Not Otherwise Supported by the Record.

PHMSA proposes to amend 49 C.F.R. § 192.705(b) to require operators to conduct pipeline ROW patrols "at least 12 times per calendar year at intervals not exceeding 45 days."[97] Adopting the Agency's proposal would significantly increase the number of required pipeline ROW patrols from the intervals currently prescribed in § 192.705(b), *i.e.*, at least once, twice, or four times per calendar year, depending on the class location and other factors. The Gas Gathering Industry Commenters do not support the proposed amendment for the following reasons.

PHMSA failed to conduct an adequate risk assessment. The Agency erroneously assumed in the PRIA that Type A gathering line operators already conduct monthly ROW patrols.[98] As support for that assumption, PHMSA cited to a practice purportedly followed by a single gas

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[96] *Id.* at 31,974.
[97] *Id.*
[98] PRIA at 37.

transmission operator in California in 2019 of conducting monthly ROW patrols.[99] The Agency also cited to the experience of its own subject matter experts (SMEs) that gas transmission line operators follow a common practice of conducting monthly ROW patrols, and that Type A gathering line operators likely follow the same practice because of the similarity in operating conditions to gas transmission lines.[100] The practice of a single transmission line operator—and otherwise unsubstantiated assertions by Agency SMEs—do not provide a legitimate basis for assuming that *all* transmission line operators conduct monthly ROW patrols. Nor do they provide a legitimate basis for extending that assumption even further to *all* Type A gathering line operators simply because of the alleged operational similarities between Type A gathering lines and transmission lines.[101]

PHMSA did not identify any benefits that are directly associated with increasing the frequency of ROW patrols in the PRIA. The Agency generally identified monetized benefits associated with reductions in methane emissions and avoided losses of natural gas, as well as other unquantified health benefits from enhanced leak detection practices.[102] However, PHMSA made no effort to attribute any of these benefits to the proposed increase in ROW patrolling. The Agency did not identify any general benefits would result from the proposal, let alone identify the incremental benefits of increasing the frequency of ROW patrols from the current risk-based intervals of 1, 2, or 4 times per year to 12 times per year in all cases.

Nor is there any evidence to suggest that the current ROW patrolling intervals are inadequate, or that requiring more frequent patrols would promote public safety or protect the environment. Conducting aerial ROW patrols at a greater frequency, for example, would not be beneficial for leak detection purposes as the proposed 5 parts per million (ppm) within 5 feet standard prohibits the use of commercially available aerial leak detection technologies. There is also no indication that more frequent ROW patrolling is necessary to address construction activity or other factors affecting the safety and operation of Type A gathering lines. Simply put, nothing in the record justifies the proposed increase in ROW patrolling, either from a cost-benefit, public safety, or environmental protection perspective. Accordingly, the Agency must retain the existing ROW patrolling requirements in Section 192.705.

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[99] *Id.*

[100] *Id.*

[101] The Agency's ROW patrolling regulation contradicts the assumptions in the PRIA. 49 C.F.R. § 192.705. The maximum ROW patrolling intervals for Type A gas gathering lines are once, twice, or four times per calendar, depending on the class location and presence of highway or railroad crossings. *Id.* § 192.705(b). While operating pressure is one of the factors that might require ROW patrolling to occur at a greater frequency, the other factors identified in the regulation include pipeline size, class location, terrain, and weather. *Id.* The regulation does not, in other words, support the proposition that a similarity in operating pressures means that operators of transmission and Type A gathering lines already conduct monthly ROW patrols. If anything, the regulation demonstrates that a number of relevant factors would need to be considered in determining whether operators conduct ROW patrols at a frequency greater than the maximum intervals prescribed in 49 C.F.R. § 192.705(b).

[102] PRIA at 72.

l. The Risk Assessment for the Proposed Changes to the Leakage Survey Requirements is Inadequate and the Proposal is Otherwise Unreasonable.

PHMSA is proposing to change the leakage surveys requirements in Part 192 for Type A, B, and C gathering lines.[103] Operators of Type A and B gathering lines are currently required to conduct leakage surveys at least once each calendar year, at intervals not exceeding 15 months, except for pipelines that transport unodorized gas. Operators of unodorized pipelines must conduct leakage surveys at least twice each calendar year, at intervals not to exceed 7 ½ months, for Class 3 locations, and at least four times each calendar year, at intervals not to exceed 4 ½ months, in Class 4 locations. Leakage surveys of Type C gathering lines that are greater than 16 inches in outside diameter must be conducted at the same intervals as Type A and Type B gathering lines. Leakage surveys of Type C gathering lines that are 16 inches or less in outside diameter must be conducted at the same intervals as Type A and Type B gathering lines, but only if there is a building intended for human occupancy or other impacted site within the potential impact circle or class location unit for the segment. Leakage surveys of smaller diameter Type C lines are otherwise not required.

The Proposed Rule would require operators of Type A, B, and C gathering lines to conduct leakage surveys in accordance with the following schedule:

- For pipelines outside of high consequence areas (HCAs), at least once per calendar year, at intervals not exceeding 15 months.
- For pipelines inside of HCAs, at least twice per calendar year, at intervals not exceeding 7 ½ months, in Class 1, Class 2, and Class 3 locations, and at least four times per calendar year, at intervals not exceeding 4 ½ months, in Class 4 locations.
- For pipelines transporting unodorized gas, at least twice per calendar year, at intervals not exceeding 7 ½ months, in Class 3 locations, and at least four times per year, at intervals not exceeding 4 ½ months, in Class 4 locations.
- For all valves, flanges, pipeline tie-ins with valves and flanges, inline inspection (ILI) launchers and receivers, and pipelines known to leak based on material, design, or past operating and maintenance history, at least twice per calendar year, at intervals not exceeding 7 ½ months, in Class 1, Class 2, and Class 3 locations, and at least four times per calendar year, not exceeding 4 ½ months, in Class 4 locations.[104]

Operators of Type A, B, and C gathering lines would need to comply with the proposed ALDP requirements in conducting leakage surveys, except that operators may submit a request under 49 C.F.R. § 192.18 to use human or animal senses in conducting leakage surveys for

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[103] 49 C.F.R. § 192.9(c) (requiring Type A gathering line operators to comply with the leak survey requirements for transmission lines in 49 C.F.R. § 192.706), (d)(8) (requiring Type B gathering line operators to "[c]onduct leakage surveys in accordance with the requirements for transmission lines in § 192.706, using leak-detection equipment, and promptly repair hazardous leaks in accordance with § 192.703(c)"), (e)(1)(vii) (requiring Type C gathering line operators to "[c]onduct leakage surveys in accordance with the requirements for transmission lines in § 192.706 using leak-detection equipment, and promptly repair hazardous leaks in accordance with § 192.703(c)," subject to the exception in § 192.9(f) for pipeline segments that are 16 inches or less in diameter).

[104] Proposed Rule, 88 Fed. Reg. at 31,975.

segments in Class 1 or 2 locations.[105] If a request is submitted under 49 C.F.R. § 192.18, the operator "must include tests or analyses demonstrating that the survey method would meet" certain provisions in the proposed ALDP requirements.[106]

The risk assessment for the proposed changes to the leakage surveys requirements for gas gathering lines does not comply with Section 60102(b)(3). PHMSA did not consider any non-regulatory options in conducting the risk assessment for the proposed changes for Type C gathering lines and only considered regulatory options that satisfied the rulemaking mandate in Section 113. The Agency did not consider the non-public-utility status of Type C gathering lines in evaluating the costs of the proposal, or the information and other data that operators of these pipelines are now required to submit to PHMSA in incident, safety-related condition, and annual reports. Nor did the Agency consider the unique impact of applying more frequent leakage survey requirements using advanced leak detection technologies to Type C gathering lines, which only recently became regulated for the first time, had compliance deadlines that did not run until the eve of the Proposed Rule, and are subject to an exercise of enforcement discretion that does not expire until next year.

With respect to the other aspects of the proposed risk assessment, the Agency relies primarily on two sources of authority in estimating the costs of the additional leakage surveys for Type A, B, and C gathering lines. The first source of authority is a 2014 state public utility proceeding in California involving an operator with no onshore gas gathering lines.[107] The second source of authority is PHMSA's FRIA for the November 2021 gas gathering line rule, which provides a cost estimate of $500 per mile for conducting leakage surveys without citing to any supporting authority.[108] These two sources of authority do not provide a sufficient basis for extrapolating the potential costs of conducting additional leakage surveys for the gathering sector of the gas pipeline industry. Nor do they account for the market conditions that will arise from simultaneously requiring increased leakage surveys across all sectors of the gas pipeline industry at the same time.

The Agency failed to quantify the safety benefits of the proposed changes to the leakage survey requirements. As the D.C. Circuit recently explained in *GPA Midstream Ass'n*, PHMSA must adequately identify the benefits of a proposed standard to comply with risk assessment requirements in the Pipeline Safety Act[109] and cannot simply offer a conclusory explanation for failing to quantify those benefits.[110] The Agency clearly did not meet that obligation in conducting

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[105] *Id.* at 31,930, 31,976

[106] *Id.* at 31,974.

[107] PRIA at 41, 142.

[108] *Id.* As noted *supra* n.42, the 2021 FRIA relied heavily on information that IPAA purportedly provided to the Agency during a 2006 rulemaking proceeding. PHMSA recently acknowledged that the historical data submitted by IPAA is no longer available for review. Letter from Tristan H. Brown, Deputy Administrator to Mathew Hite, GPA Midstream (Apr. 15, 2022), https://www.regulations.gov/document/PHMSA-2011-0023-0507. The Agency cannot prepare an adequate risk assessment by relying on outdated, and otherwise unavailable, data from a years-old rulemaking proceeding. *See* Appeal of Decision Denying Petition for Reconsideration at 7-8, PHMSA-2011-0023, https://www.regulations.gov/document/PHMSA-2011-0023-0509.

[109] *GPA Midstream Ass'n*, 67 F.4th at 1200-1201.

[110] *Id.* at 1200 (noting that "[q]uantifying benefits always requires making projections," and that "[w]ithout quantified benefits to compare against costs, it is not apparent just how the agency went about weighing the benefits against the costs").

the risk assessment for the Proposed Rule, stating that "[d]ue to the difficulty of predicting the probability of the leaks estimated above to result in injuries, fatalities, or other damages and the severity of the damages, PHMSA did not monetize the safety benefits of the proposed rule but notes that these benefits could be significant."[111] This is precisely the kind of conclusory explanation that the D.C. Circuit found inadequate in *GPA Midstream Ass'n*.

The safety benefits of the proposed increase in the leak survey requirements are clearly relevant to making the reasoned cost-benefit determination required under the Pipeline Safety Act, particularly for small leaks. As explained in the technical report prepared by Highwood Emissions Management (Highwood), any reduction in methane emissions that would result from requiring operators to conduct leak surveys to detect small leaks is minimal, and any justification for imposing that obligation requires consideration of the safety benefits and resulting costs.[112] Failing to provide that information in the risk assessment deprives the public and the GPAC of the opportunity to consider the benefits of the Proposed Rule during the subsequent phases of the rulemaking process.

m. The Risk Assessment for the Proposed Leak Grading and Repair Criteria for Type A, B, and C Gathering Lines is Inadequate, and the Proposal is Otherwise Unreasonable.

The Proposed Rule would require operators of Types A, B, and C gathering lines to comply with new criteria for grading and repairing leaks.[113] All leaks would have to be graded as either a grade 1, grade 2, or grade 3. Operators would need to take immediate and continuous action to promptly repair a grade 1 leak. Operators would need to repair a grade 2 leak within six months of detection, subject to re-evaluation every thirty days until the repair is complete. However, operators would need to repair a grade 2 leak on Type A gathering line in Class 3 or 4 location within 30 days, or if a repair cannot be completed by that time due to permitting requirements or parts availability, take continuous action to monitor and repair the leak. All known grade 2 leaks existing on the effective date of the final rule would need to be repaired within 12 months.

Operators would have to repair a grade 3 leak with 24 months of detection unless the operator schedules to replace the segment within five years of detection. A grade 3 leak would need to be re-evaluated every six months until the repair is complete. All known grade 3 leaks existing on the effective date of the final rule would have to be repaired within 36 months. An operator may request an extension to repair a grade 3 leak using the 90-day prior notice and no-objection process in 49 C.F.R. § 192.18. The Proposed Rule would also require operators to comply with post-repair inspection requirements, keep records related to the grading and investigation of the leak for five years, and keep records related to the repair or remediation of a leak for the life of the pipe.

The risk assessment for the proposed leak grading and repair requirements for regulated gathering lines does not comply with Section 60102(b)(3). As to Type C gathering lines, PHMSA did not consider any non-regulatory options and erred in only considering regulatory options that

[111] PRIA at 91.
[112] Highwood Report at 2.
[113] Proposed Rule, 88 Fed. Reg. at 31,960, 31,975.

satisfied the rulemaking mandate in Section 113. The Agency did not consider the non-public-utility status of Type C gathering lines in evaluating the costs of the proposal, or any of the information and other data that operators of these pipelines are now required to submit to PHMSA in incident, safety-related condition, and annual reports. Nor did the Agency consider the unique impact of applying more stringent leak grading and repair requirements to Type C gathering lines, which only became jurisdictional last year, had initial compliance deadlines that did not run until the eve of the Proposed Rule's publication, and are subject to an exercise of enforcement discretion that does not expire until next year.

With respect to the other aspects of the risk assessment, the PRIA states that "PHMSA assumed for purposes of this analysis that operators repair all leaks on gas transmission and gas gathering lines within the year they are discovered."[114] No authority is cited to support this assumption, and in any event PHMSA is proposing to adopt leak grading criteria that are more stringent than longstanding regulations and industry practices, some of which will require operators to repair leaks that could otherwise be monitored for more than a year. Assuming that gathering line operators are repairing all leaks within one year is simply unreasonable, particularly given the changes to the definition of "leak or hazardous leak" and the criteria for grading and repairing leaks in the Proposed Rule.

The PRIA relies on a 0.0235 leaks-per-mile-per-year average incidence rate for Type A, B, and C gathering lines, citing data from annual reports submitted between 2015 and 2020.[115] PHMSA did not distinguish between Type A and Type B gathering lines in articulating the average leak incidence rate, even though the mileage reported for these two types of gathering lines differed significantly during the 2015-2020 period, *i.e.*, there were approximately 8,200 to 8,600 miles of Type A gathering lines and approximately 3,100 to 3,300 miles of Type B gathering lines. The Agency also failed to explain how the average leak incidence rate accounts for the high- and low-stress-level threshold that separates Type A and Type B gathering lines, which bears directly on the probability of experiencing a leak.[116]

The Agency did not use any data for Type C gathering lines in developing the average leak incidence rate either. Instead, PHMSA assumed that "[u]sing data for Type A and B gathering lines is reasonable given similarities in function, requirements, and operational characteristics."[117] The Agency's reasoning fails to account for the differences between Type A gathering lines, which are more similar operationally to Type C lines from a stress level perspective, and Type B gathering lines, which are more similar to Type C lines from a Part 192 requirements perspective. PHMSA also has access to new annual report data for more than 93,000 miles of Type C gathering lines. At the very least, the Agency should have considered whether the new annual report data corroborated or undermined the rationale for applying the same average leak incidence rate to all regulated gas gathering lines.

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[114] PRIA at 43.
[115] *Id.* at 103.
[116] Interstate Natural Gas Association of America/American Gas Association, Final Report No. 13-180, Leak vs. Rupture Thresholds for Materials and Construction Anomalies (Dec. 15, 2013), https://ingaa.org/wp-content/uploads/2019/06/36514.pdf.
[117] PRIA at 43.

Highwood observes that the average leak incidence rate that PHMSA used in the PRIA likely results in a significant underestimation of the actual leak incidence rate for the gas gathering sector in its technical report on the Proposed Rule.[118] In reaching that conclusion, Highwood explains that the Agency relied on a study conducted using aerial survey technology that could only collect data from medium- to large-point source emissions to validate the assumptions used in the PRIA.[119] Highwood explains that the study did not account for the small-point source emissions that would be subject to the proposed leak grading and repair criteria, and that PHMSA's failure to consider the absence of those small-point source emissions in relying on the study undermines the results of the risk assessment. Highwood also notes that the Agency's failure to account for leak sizes in conducting the risk assessment undermines the validity of the average leak incidence rate used in the PRIA as well.

The PRIA cites to a single proceeding involving a public utility gas transmission line operator in California to support using an average unit repair cost of $5,650 per leak for all Type A, B, and C gathering lines.[120] Using a single public utility proceeding to determine the average unit cost of leak repairs for an entirely different sector of the pipeline industry is unreasonable.[121] The PRIA also imposed an additional incremental average unit cost of $218 for the proposed post-repair follow-up inspections.[122] In calculating that additional average unit cost, the Agency assumed that these activities would take 4 hours of time, including two hours of travel time and two hours of time for confirming the repair and documentation.[123] The only support cited for these assumptions are PHMSA's best professional judgment and the comparative costs of leak rechecks from the same California ratemaking proceeding.[124] The Agency does not cite to a single project involving a gas gathering line or offer any other evidence or explanation to support the reasonableness of applying the assumptions to gathering line operators.

Highwood provides a far more detailed and realistic repair costs for gas gathering lines in its technical report on the Proposed Rule.[125] Relying on information provided by gathering line operators, Highwood estimates that the average cost of repairing a leak is approximately $15,000, or about 3 times more the estimate used in the PRIA. Unlike PHMSA, Highwood also provides estimates for the average cost of repairing leaks for each of the three grades proposed by the Agency, *i.e.*, $15,000 or less for grade 3 leaks, $25,000 to $100,000 for grade 2 leaks, and $100,000 to $200,000 for grade 1 leaks. Highwood accounts for several typical costs that PHMSA failed to discuss in the PRIA as well, including $1,500 per day for portable flares or compressors, $1500 per day for hydro-vac services, $7500 per day for excavators, $1000 per day welders, and $500 per day for pipe fitters. Highwood's estimates make clear that the cost assumptions used in the PRIA are incomplete and unreasonable, both for the larger volume releases that might occur on

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118 Highwood Report at 7.
119 *Id.*
120 PRIA at 44.
121 *GPA Midstream Ass'n*, 67 F.4th at 1198 ("A similarity in risk, operating pressures, or diameters, however, does not mean the safety standard is practicable or has similar benefits and costs when applied to a different sector of the pipeline industry.").
122 PRIA at 44.
123 *Id.*
124 *Id.* 44 & n.39.
125 Highwood Report at 8.

Type A, B, and C gathering lines and for the smaller volume releases on Type A and C gathering lines that would be subject to the accelerated grade 2 leak repair deadlines.[126]

The PRIA assumes that the proposed leak grading and repair requirements "are generally consistent with existing practices of gas gathering and transmission operators" when that is clearly not the case.[127] The proposed grade 1 criteria would include "any leak that can be seen, heard, or felt," even though the comparable provision in the GPTC guidance limits the applicability of that standard to "locations that may endanger the general public or property." Indeed, the "any leak that can be seen, heard, or felt" in that proposal would effectively supersede all of the other criteria and make every leak on a pipeline a grade 1. All grade 2 leaks would need to be repaired within 6 months, even though the GPTC guidance allows up to one calendar year, not to exceed 15 months, to repair certain grade 2 leaks. All grade 2 leaks on Type A gathering lines in Class 3 or 4 location would need to be repaired within 30 days, even though the GPTC guidance allows for a longer period depending on the facts and circumstances presented. Any leak on a Type A or C gathering line that does not qualify as a grade 1 leak would need to be classified as grade 2 leak, even though the comparable provision is the GPTC guidance is limited to pipelines operating at stress level of 30 percent of SMYS or greater in a Class 3 or 4 location. PHMSA says nothing in the PRIA about the effect of these proposed departures from longstanding industry practices on the grading and repair of leaks. Nor does the PRIA discuss the costs, benefits, and other impacts of requiring all existing grade 2 leaks to be repaired within 12 months of the final rule, particularly for operators of Type A and C gathering lines, who would no longer be able to treat any leaks as a grade 3.

The Agency failed to quantify the safety benefits of the proposed changes to the leak grading and repair requirements, purportedly "[d]ue to the difficulty of predicting the probability of the leaks estimated . . . to result in injuries, fatalities, or other damages and the severity of the damages[.]"[128] The Agency's conclusory explanation is inadequate,[129] and its failure to quantify the safety benefits undermines the validity of the entire risk assessment. Although PHMSA dedicates significant portions of the PRIA to discussing the potential environmental benefits of the proposed leak grading and repair requirements, the safety benefits clearly predominate as the size of the affected leak decreases. Highwood's technical report confirms that point, noting that the environmental benefits of detecting, grading, and repairing small leaks are minimal at best.[130] Without an adequate evaluation of the safety benefits, PHMSA's proposal to require the detection, grading, and repair of small leaks—particularly given the 5 ppm with 5 feet threshold—cannot be justified under the cost-benefit provision in the Pipeline Safety Act.

The proposed leak grading and repair requirements are unsupported and unreasonable. The Proposed Rule departs from longstanding industry practice in treating "any leak that can be seen, heard, or felt" on a regulated gathering line as a grade 1 leak, and treating any leak on a Type A or

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[126] The Proposed Rule would require operators of Type A and C gathering lines to treat leaks that would otherwise qualify as grade 3 leaks as grade 2 leaks. Because grade 2 leaks would be subject to accelerated repair deadlines, operators of Type A and C gathering lines would not be able to schedule these leaks for remediation during normal facility outages.
[127] PRIA at 42.
[128] *Id.* at 91.
[129] *GPA Midstream Ass'n*, 67 F.4th at1200-1201.
[130] Highwood Report at 2.

C gathering line that does not qualify as a grade 1 leak as a grade 2 leak. The record does not provide adequate support for either of these proposals. The proposal to accelerate the deadlines for repairing the leaks. The combined effect of these proposed changes is a leak grading and repair scheme that is unachievable and impractical.

The Agency's proposal to only treat a "repair" as being complete when the operator obtains a reading of "0% gas" is unjustified.[131] EPA's comparable standards, which PHMSA agrees should be allowed to govern at compressor stations, treat a repair as complete if the gas reading falls below the applicable leak detection threshold.[132] The Agency provides no rationale for rejecting EPA's approach if a repair occurs outside of a compressor station and accepting that approach if a repair occurs inside of a compressor station. PHMSA also fails to consider the impracticability of satisfying the 0% gas reading requirement in environments where other sources of methane emissions are present, such as coal mines and wetlands, and of continuing to require repairs based on readings that fall below the leak detection threshold (and which would not otherwise require any remedial action under the proposed LDAR requirements). Nor does the Agency's proposal address the use of temporary and permanent repairs in meeting the deadlines applicable to grade 1, grade 2, or grade 3 leaks. If an operator responds to a leak by implementing a temporary repair or isolating the affected portion of the pipeline, these actions should qualify as "repairs" for purposes of the Proposed Rule.

Finally, the Agency proposes to require that operators maintain records of repairs "for the life of the pipeline," leak detection equipment calibration records "for the life of the equipment," and records relating to the repair and replacement of pressure relief devices "for the life of the pipeline."[133] PHMSA provides no justification for these lifelong recordkeeping obligations. EPA only requires repair and calibration records to be maintained for five years or less, not indefinitely.[134] The Agency should follow EPA's lead on this issue.

n. The Risk Assessment for the Proposed ALDP Requirements for Type A, B, and C Gathering Lines is Inadequate, and the Proposal is Otherwise Unreasonable.

The Proposed Rule would require operators of Types A, B, and C gathering lines to develop an ALDP that includes a list of the leak detection equipment that the operator will use for leakage surveys, pinpointing leaks, and investigating leaks.[135] The leak detection equipment would need to have a sensitivity of 5 ppm for the gas being surveyed and an operator would need to validate the sensitivity of the equipment before use on a survey by testing with a known quantity of gas. Operators would need to prepare a documented analysis to determine what leak detection equipment to use after considering certain elements and technologies.

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[131] Proposed Rule, 88 Fed. Reg. at 31,943.
[132] *See, e.g.*, 40 C.F.R. §§ 60.481a (leaking component under Subpart VVa repaired when it is re-monitored "to verify that emissions from the equipment are below the applicable leak definition"); 60.5430 (Subpart OOOO adopting definition of "repair" from Subpart VVa).
[133] Proposed Rule, 88 Fed. Reg. at 31,968.
[134] *See* 40 C.F.R. §§ 60.5420a(c)(15)(vii)(I)(4)-(8) (Subpart OOOOa requires repair records be maintained for five years); *id.* § 60.5420a(c)(15)(vii)(H) (Subpart OOOOa: calibration records maintained for five years); *id.* § 60.486a(c)(3) (Subpart VVA: repair records maintained for two years); *id.* § 60.486a(e)(8) (calibration records maintained for two years).
[135] Proposed Rule, 88 Fed. Reg. at 31,977.

The ALDP would also need to include written procedures detailing the operator's leak detection practices for conducting leakage surveys, pinpointing and investigating leaks, validating leak detection equipment, maintaining and calibrating leak detection equipment, and evaluating and improving the ADLP. An evaluation of the ALDP would need to occur every year, not to exceed an interval of 15 months. The ALDP would need to meet PHMSA's proposed performance standards as well. The ALDP would need to be capable of detecting a leak that produces a reading of 5 ppm when measured from a distance of 5 feet from the pipeline. Operators of Type A, B, and C gathering line operators would be allowed to use the notification and no-objection process in 49 C.F.R. § 192.18 to propose alternative ALDP performance standards (and corresponding leak detection equipment) for pipelines in Class 1 and 2 locations.

The risk assessment for the proposed ALDP requirements does not comply with Section 60102(b)(3). PHMSA did not consider any non-regulatory options in conducting the risk assessment for the proposed ALDP for Type C gathering lines and only considered regulatory options that satisfied the rulemaking mandate in Section 113. The Agency did not consider the non-public-utility status of Type C gathering lines in evaluating the costs of the proposed ALDP, or the information and other data that operators of these pipelines are now required to submit to PHMSA in incident, safety-related condition, and annual reports. Nor did the Agency consider the unique impact of applying the proposed ALDP requirements to Type C gathering lines, which only became regulated for the first time in more than five decades last year, had initial compliance deadlines that did not run until the eve of the Proposed Rule's publication, and are subject to an exercise of enforcement discretion that does not expire until next year.

The record does not support the proposed 5-ppm-within-5-feet leak detection threshold. That threshold is 10,000 times below the sensitivity needed to detect the lower explosive limit for natural gas, and 100 times more conservative than the definition of a leak in EPA's LDAR regulations. PHMSA does not provide a legitimate safety or environmental rationale for establishing a leak detection threshold with that level of conservatism and fails to recognize the importance of atmospheric stability in meeting that standard in the field. Nor does the Agency recognize that setting a threshold so low will result in the detection of non-pipeline sources of methane emissions (both manmade and natural), and that operators will be forced to grade, monitor, and repair these non-jurisdictional leaks until a "0% gas reading" is obtained. Making operators engage in the never-ending task of grading, monitoring, and repairing non-jurisdictional leaks will require the investment of considerable resources without producing any corresponding safety or environmental benefits.

Adopting the proposed 5-ppm-within-5-feet threshold would also be self-defeating. As Highwood demonstrates in its technical report on the Proposed Rule, many commercially available leak detection technologies cannot satisfy that standard and would not be authorized for use under the proposed ALDP.[136] Indeed, various provisions in the proposed ALDP suggest that any technology used in conducting a leak survey would either need to meet 5-ppm-within-5-feet standard or be confirmed by another technology that meets 5-ppm-within-5-feet standard. There is no benefit to incurring the cost of using even the most advanced leak detection technology that does not satisfy the 5-ppm-within-5-feet threshold under that approach. Rather than creating a

[136] Highwood Report at 2, 4-5, 35.

"win-win" scenario for interested stakeholders, the proposed 5-ppm-within-5-feet standard would be a "lose-lose" proposition for many of the very technologies that Congress wanted to promote in enacting Section 113 of the 2020 PIPES Act.

PHMSA should develop alternatives to the across-the-board, 5-ppm-within-5-feet standard that account for other relevant factors, such as the reliability of the equipment in field conditions, practicality of using equipment on belowground and aboveground facilities, and cost-effectiveness, *etc.* For example, EPA relied on cost effectiveness evaluations, examinations of leak definitions under similar state and federal statutes, experience with various leak definitions required by consent decrees, and the ability to repair detected leaks, among other factors, in developing its regulations.[137] PHMSA should follow the same path and perform a holistic analysis that considers a variety of factor before deciding on whether to set a particular leak detection threshold for one or more technologies in the ALDP. The Agency should also make every effort to harmonize its leak detection thresholds with the requirements in LDAR programs administered by EPA and other federal and state agencies.

PHMSA should not rely on methane concentration—or certainly not on methane concentration alone—in establishing any performance standard for leak detection technologies in the ALDP. The Highwood Report demonstrates that an appropriate flow-rate-based metric can be used to achieve substantial reductions in methane emissions while facilitating the cost-effective detection, grading, and repair of leaks. The Agency acknowledges as much in the Proposed Rule and even urges operators to include methods for measuring flow rate in the ALDP,[138] but then *rejects* the use of a flow rate metric by claiming that "no commenter provided a suggestion for how this could be implemented."[139] The record shows that an appropriate flow-based rate metric can be used as PHMSA cites to and relies upon studies analyzing or estimating emission flow rates throughout the Proposed Rule.[140] EPA's Supplemental Proposed Rule for Subparts OOOOb and OOOOc also proposed a frequency matrix for different alternative methane detection technologies based on the detection limit of the instrument package. While the Gas Gathering Industry Commenters may not agree with every aspect of these studies or EPA's proposed technology matrix, there is no dispute that an emission flow rate is a commonly used metric and would be a more appropriate threshold to use than methane concentration alone.

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[137] *See* Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. 52,738, 52,764-66 (Aug. 23, 2011) (evaluating potential leak definitions of 10,000 ppm and 500 ppm based on cost effectiveness for Subpart OOOO); Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry; Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, 71 Fed. Reg. 65,302, 65,305 (Nov. 7, 2006) (establishing 500 ppm leak definition under Subpart VV based on other regulatory leak definitions and experience under consent decrees); Hazardous Wast Treatment, Storage, and Disposal Facilities; Air Emission Standards for Volatile Organics Control, 52 Fed. Reg. 3,748, 3,757-58 (Feb. 5, 1987) (10,000 ppm leak definition informed by control technologies, the frequency of monitoring, and the ability to repair a leak to below 10,000 ppm).

[138] Proposed Rule, 88 Fed. Reg. at 31,936.

[139] *Id.* at 31,936., n.240.

[140] *See, e.g.*, *id.* at 31,904, n.106 (citing Chen et al., "Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey," 56 Environ. Sci. Technol. 4317 (Mar. 23 2022)); *id.* at 31,912, n. 148 (citing Yu et al., "Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin," Environ. Sci. Technol. Lett. (Nov. 8, 2022).

Finally, even if the Agency retains the 5-ppm-within-5-feet threshold as a performance standard for certain leak detection technologies, PHMSA should clarify that the threshold only applies for purposes of determining the sensitivity of the equipment and does not require that the equipment itself be located within 5 feet of the pipeline when the operator conducts a leak survey.

o. PHMSA Should Reevaluate the Proposed Expansion of the Operator Qualification Requirements and Clarify the Proposed Requirements for Minimizing Emissions from Blowdowns and Maintenance and Adjustment of Pressure Relief Device Configuration.

The Agency is proposing to apply the operator qualification (OQ) requirements in subpart N to individuals who conduct leaks surveys, investigations, grading, and repairs.[141] The Proposed Rule would require that "[i]ndividuals qualified under subpart N must also possess training, experience, and knowledge in the field of leakage survey, leak investigation, and leak grading, including documented work history or training associated with those activities."[142] The OQ requirements already provide a comprehensive framework for identifying covered tasks and ensuring that individuals are qualified to perform those covered tasks. There is no reason to require a specific regulation that adds leak-related operations and maintenance activities to the OQ program. Nor is there any reason to adopt supplemental requirements for "training, experience, and knowledge" or "documented work history or training" for individuals responsible for performing leak-related operations and maintenance activities. Accordingly, the Agency should eliminate the proposed OQ regulation from the final rule.

PHMSA is proposing to require that operators use certain methods "to prevent or minimize the release of gas to the environment" during intentional releases, such as blowdowns or venting for scheduled repairs, construction, operations, or maintenance activities.[143] The Agency is also proposing to require that operators document the methodologies used in satisfying these requirements.[144] PHMSA should clarify that the documentation requirement can generally be satisfied through the development and implementation of written procedures that apply to the pipeline. There is no need for operators to document the application of the methodologies used to minimize the release of gas during each specific intentional release that occurs on a pipeline. Such a requirement would impose undue recordkeeping burdens, particularly when applied to routine activities that involve small, intentional releases of gas, such as pigging or meter run maintenance activities.

The Agency proposes to require that operators develop, maintain, and follow written procedures for assessing the proper function of pressure limiting or relief device and repairing or replacing failed devices. PHMSA should also clarify that the proposed criteria for responding to failed devices apply individually and not in the conjunctive. Otherwise, an operator that chooses to repair or replace a failed device will be required to comply with unnecessary assessment criteria. The requirement to maintain records for the "repair, replacement, or reconfiguration (including any engineering analyses)" of a pressure relief device for the life of a pipeline are unnecessary and

[141] Proposed Rule, 88 Fed. Reg. at 31,978.
[142] *Id.*
[143] Proposed Rule, 88 Fed. Reg. at 31,978.
[144] *Id.*

unduly burdensome. The Agency should limit that requirement to 5 years, or for so long as a repaired or replaced relief device remains in service or until the next reconfiguration of a relief device that is reconfigured.

p. The Record Does Not Support Applying the Proposed LDAR Requirements to Offshore Gas Gathering Lines.

PHMSA proposes to apply the LDAR requirements to offshore gas gathering lines. Like Type C onshore gas gathering lines, offshore gas gathering lines are not subject to the rulemaking mandate in Section 113, and the Agency failed to comply with the risk assessment requirements in Section 60102(b)(3) in developing the proposed LDAR requirements for offshore gas gathering lines, particularly with respect to the consideration of the costs and benefits from a safety perspective of applying an onshore LDAR program in an offshore environment. The proposed requirements for conducting leak surveys, grading and repairing leaks, and implementing an ALDP also present entirely different compliance challenges in offshore locations, which make those provisions even more unreasonable than in onshore locations. In short, the record does not support applying the proposed LDAR requirements to offshore gas gathering lines, and those pipelines should be excluded from further consideration in this proceeding.

q. PHMSA Cannot Prescribe Safety Standards in the Final Rule for Any of the General Topics Referenced in the Proposed Rule.

At various points throughout the Proposed Rule, the Agency refers to a general topic with no supporting detail or analysis and states that PHMSA may include regulations related to that topic in "a final rule in this proceeding".[145] The general topics that the Agency references in the Proposed Rule include:

- Application of substantive safety requirements to Type R pipelines.[146]
- Leak detection and repair requirements for hydrogen pipelines.[147]
- Leakage survey and leak detection equipment requirements for undergrounds natural gas storage facilities.[148]
- Including references to specific kinds of leak detection equipment.[149]
- Adding new criteria for identifying grade 1 and grade 2 leaks.[150]
- Establishing an emission mitigation reduction threshold greater than the proposed 50%.[151]

PHMSA cannot include legally binding requirements on these general topics in the final rule without violating the Administrative Procedure Act. The APA requires the Agency to provide notice of "either the terms or substance of the proposed rule or a description of the subject and

[145] *Id.* at 31,926-31,937.
[146] *Id.* at 31,932.
[147] *Id.* at 31,926.
[148] *Id.* at 31,926.
[149] *Id.* at 31,934.
[150] *Id.* at 31,940 and 31,942.
[151] *Id.* at 31,949.

issues involved."[152] The APA also makes clear that the notice provided by PHMSA must be sufficient to "give interested persons an opportunity to participate in the rule making through submission of written data, views, or arguments."[153] Merely mentioning a general topic in a proposed rule does not provide the fair notice required to solicit meaningful public comment,[154] particularly when the Agency has failed to "describe the range of alternatives being considered with reasonable specificity."[155] Nor can PHMSA rely on the public comments submitted in response to the Proposed Rule to create the notice that the APA requires after-the-fact,[156] or prescribe a regulation in the final rule that is based on technical studies and data not made available during the public comment period.[157]

The Agency would also be violating the additional and more stringent rulemaking requirements in the Pipeline Safety Act by including regulations on these general topics in the final rule.[158] PHMSA is required to prepare a risk assessment for each proposed standard under the Pipeline Safety Act, and that risk assessment must identify the regulatory and non-regulatory options considered, as well as the costs and benefits associated with the proposed standard, provide the reasons for selecting the proposed standard, and identify the technical data or other information that provides the basis for the risk assessment and proposed standard.[159] The public must be afforded the opportunity to review and provide comments on the risk assessment during the rulemaking process, and the GPAC must be afforded the same opportunity in performing the peer review function intended under the Pipeline Safety Act.[160] The Agency has not prepared a risk assessment for the general topics referenced in the Proposed Rule, the public has not been afforded the opportunity to review and provide comments on that risk assessment, and the GPAC will not be able to consider the same as part of any subsequent peer review process. Accordingly, the Pipeline Safety Act prohibits PHMSA from prescribing any safety standards in the final rule related to these general topics.

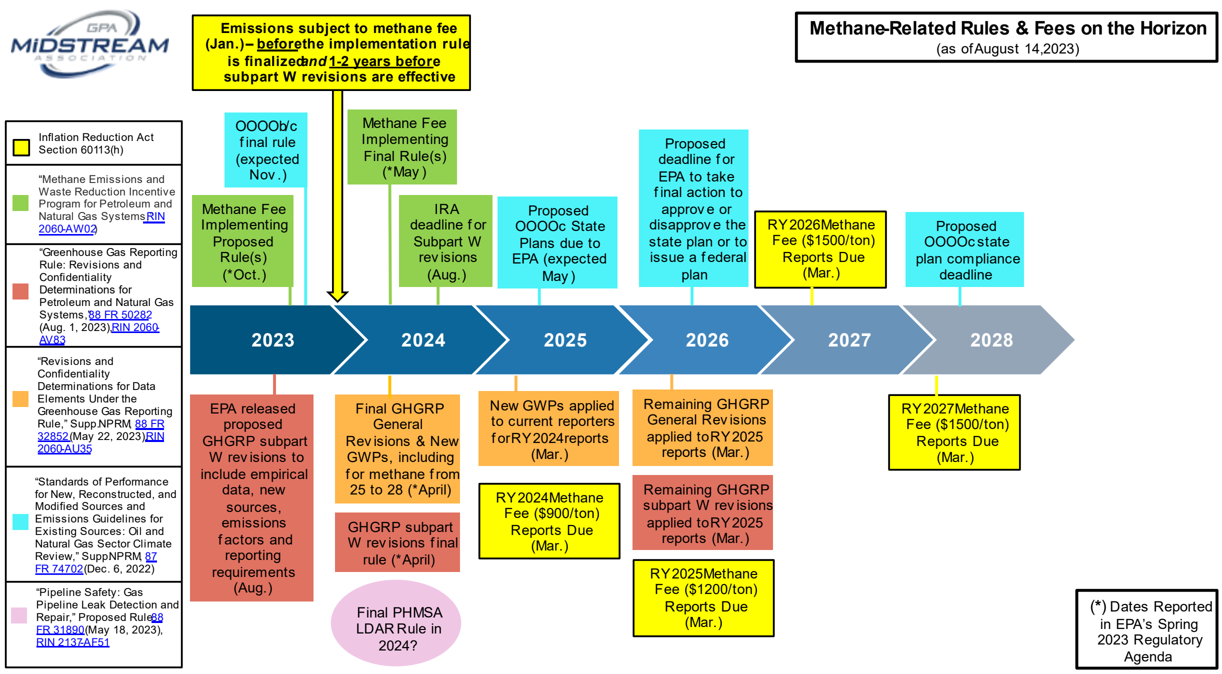
r. PHMSA Must Consider Other Pending Methane-Related Rules and Fees in Prescribing any Final Regulations in this Proceeding.

As previously discussed and highlighted in the table below, there are several key inconsistencies between the provisions in the Proposed Rule and EPA's comparable LDAR requirements. PHMSA should eliminate these inconsistencies to the maximum extent practicable to avoid imposing unnecessary burdens and increased compliance costs on gathering line operators.

[152] 5 U.S.C. § 553(b)(3).
[153] *Id.* § 553(c).
[154] *Mid-Continent Nail Corp. v. United States,* 846 F.3d 1364, 1378 (Fed. Cir. 2017).
[155] *Small Refiner Lead Phase-Down Task Force v. EPA,* 705 F.2d 506, 549 (D.C. Cir. 1983).
[156] *American Fed'n of Labor and Congress of Indus. Organizations v. Donovan,* 757 F.2d 330, 340 (D.C. Cir. 1985) (noting that an agency "cannot bootstrap notice from a comment.)"
[157] *American Public Gas Ass'n v. United States Dep't of Energy*, 72 F.4th 1324, 1337 (D.C. Cir. 2023) (internal citations omitted).
[158] 49 U.S.C. § 60102.
[159] *Id.* § 60102(b)(2)-(3).
[160] *GPA Midstream Ass'n,* 67 F.4th at 1197-1198.

LDAR	EPA Methane Proposal	PHMSA Proposal
Inconsistent limits	EPA - methane leaks ≥ 500 ppm	PHMSA - methane leaks ≥ 5 ppm
Inconsistent repair	EPA - leak repaired < 500 ppm	PHMSA – leak repaired "0% gas"
Inconsistent basis	EPA – used cost benefit analysis	PHMSA – inadequate cost benefit analysis
"Hazard" standard	EPA – no determination	PHMSA - all leaks
Recordkeeping	EPA – five years	PHMSA – life of the equipment

The Gas Gathering Industry Commenters also note that PHMSA failed to consider the potential impact of other pending methane-related rules and fees in developing the Proposed Rule and PRIA. As illustrated in the graphic below, there at least four parallel EPA rulemaking proceedings underway that bear directly on the issues that the Agency is considering in this proceeding. Gathering line operators will also be subject to additional methane fees in the coming years. PHMSA needs to consider the potential impact of these related actions in conducting the final risk assessment and establishing the effective dates and compliance dates for any final regulations prescribed in this proceeding.



V. Conclusion

The Gas Gathering Industry Commenters share PHMSA's commitment to pipeline safety and appreciate the opportunity to submit these comments on the Proposed Rule.

Sincerely,

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Dave Murk
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Technical Report

PHMSA Methane Detection Requirements Analysis

Evaluation of PHMSA's proposed monitoring technology requirements

Date
2023-08-16

Focus
Evaluation of PHMSA's proposed monitoring technology requirements. The report provides a regulation review, determining technologies available to monitor pipelines, simulating their performance, and evaluating the cost of mitigation of typical technologies available.

Team
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Prepared for
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Executive Summary

This report by Highwood Emissions Management (Highwood) evaluates the proposed monitoring technology requirements for gathering lines set forth by the Pipeline and Hazardous Materials Safety Administration (PHMSA). The purpose of this project was to interpret the regulations, assess available pipeline monitoring technologies, simulate their performance, and evaluate the associated mitigation costs. Through exploratory modelling, the report aimed to determine the sensitivity required by PHMSA's leak detection performance requirements and assess the adequacy of existing technologies.

The key findings of the report are as follows:

- Concentration-based technology requirements mandated by PHMSA cannot accurately estimate leak size without considering atmospheric stability conditions. Performance metrics like the probability of detection (POD), usually as a function of leak rate and wind speed, derived from testing are still the best way to benchmark and compare technologies.
- If only walking surveys are considered, devices meeting PHMSA requirements have a high probability (>80% chance) of detecting leaks ranging from 0.03 to 0.51 kg/hr under most atmospheric conditions.
- Framework for equivalence approval remains unclear and most commercially operational aircraft-based technologies lack the necessary sensitivity to meet PHMSA requirements (above rates).
- Limited data exist on leak incident rates and leak rates from gathering lines. Nevertheless, through the evaluation of various scenarios, it has been demonstrated that higher detection limit technologies can still achieve significant emissions reductions without requiring a significant increase in the number of repairs.

Based on these findings, the report puts forward the following recommendations:

- Regulations should consider putting forward requirements focusing on the demonstration of the probability of detecting specified emission rates, which would align with EPA standards. This shift would provide a more practical and effective approach to leak detection.
- Regulations should consider the small benefit of detecting and repairing small leaks that are not impactful for emissions mitigation. Focusing on large sources can bring substantial emissions reductions while ensuring efficient use of resources.

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1. Introduction

Methane emissions are invisible to the human eye and often unpredictable, however, innovation in methane measurement technology has significantly increased over the past decade. Advances in sensing, deployment platforms, work practices, and analytics have paved the way for a better understanding of emission sources and their impact. Currently, over 200 methane measurement solutions have appeared that range from handheld systems to satellites, stationary lasers to drones, sensors mounted to trucks and piloted aircraft. Current and emerging methane detection and quantification technologies offer a diversity of services and data products that span many orders of magnitude in spatial and temporal resolution. They differ in terms of sensitivity, survey speed, and cost. These differences allow operators to tailor their monitoring plan technology selections to the best fit-for-purpose solution for individual applications. Effective regulations should recognize the importance of flexibility to deploy appropriate, varied, and in some cases multi-layered technologies in this space to achieve the greatest reductions in emissions at the lowest cost. Effective regulations should also recognize the rapid pace of development and create a pathway for new technologies to be evaluated, approved, and enter service.

In this report, Highwood Emissions Management (Highwood) evaluated PHMSA's proposed monitoring technology requirements for gathering lines. The project began by interpreting the regulations, determining technologies available to monitor pipelines, simulating their performance, and evaluating the cost of mitigation of typical technologies available.

2. PRIA Review

2.1. NPRM Overview

On May 5, 2023, the Pipeline and Hazardous Materials Safety Administration (PHMSA) released a notice of proposed rulemaking (NPRM) for "Pipeline Safety: Gas Pipeline Leak Detection and Repair." The NPRM presents several noteworthy modifications aimed to be effective six months after the rule is finalized. Some of the changes include increased frequency of leakage survey and patrolling requirements, the introduction of leakage survey and repair requirements for liquefied natural gas (LNG) facilities, the introduction of leak grading procedures which determine repair timelines, expansion of reporting requirements and reduction of blowdowns and intentional venting. Additionally, PHMSA extended facilities in scope by including Type C gathering lines, underground natural gas storage facilities, and LNG facilities into regulated facilities. To avoid overlap with existing Environmental Protection Agency (EPA) regulations, PHMSA proposed to exempt facilities under the scope of leak detection and Repair (LDAR) regulations at 40 CFR Part 60, Subpart OOOOa, and EPA's proposed regulations that would be codified at 40 CFR Part 60, Subparts OOOOb and OOOOc. The scope of these anti-overlap provisions is unclear. Additionally, the proposed rule requires that for all leakage surveys, the operator must use leak detection technologies that meet PHMSA's proposed detection sensitivity requirements.

Advanced Leak Detection

PHMSA's proposal includes the requirement to create a comprehensive written program called the Advanced Leak Detection Program (ALDP), which requires operators to establish specific procedures for conducting leakage surveys and effectively locating and investigating leaks. Alongside other obligations, operators would be required to choose an appropriate leak detection technology that must have the capability to detect and pinpoint all leaks causing a concentration reading of 5 ppm or more when measured 5 feet from the pipeline. However, it remains uncertain whether this sensitivity threshold for leak detection devices is practical or aligns with the current technologies typically used for pipeline inspections.

Leak Grade and Repair Requirements

PHMSA also proposes a rigorous procedure for leak grading and repair, which would impose specific obligations on operators to classify and address all identified leaks in their pipeline systems. At a high-level, operators would be required to assess detected leaks and assign them to grade 1 (most severe), grade 2, or grade 3 (least severe) categories based on predetermined narrative criteria or specified percentages of the lower explosive limit (LEL). For grade 1 leaks, immediate and continuous action would be mandatory upon detection to initiate repairs. Grade 2 leaks would need to be repaired within 6 months of detection, and the operator must reassess the leak every 30 days until the repair is completed. If a grade 2 leak is located on a transmission line or Type A gathering line in a high-consequence area (HCA) or within a Class 3 or 4 location, it would require repair within 30 days. Grade 3 leaks would be required to be repaired within 24 months of detection, with reassessments occurring every 6 months until the repair is completed. However, if the operator replaces the pipeline segment containing the leak within 5 years of detection, the repair becomes unnecessary. It is important to note that PHMSA's leak grading approach differs from the concentration-based leak definition typically utilized by the EPA in its LDAR regulations, which establishes a threshold above which repairs are required. According to the proposal, all leaks detected will require repair, but the cost-effectiveness of repairing small leaks was not assessed by PHMSA.

2.2. PRIA Assumptions

For the cost-benefit analysis, PHMSA carried out a cost-benefit analysis of the proposed rule against a baseline that reflects current requirements, including leak detection, repair, and O&M practices that gas pipeline operators are currently implementing to comply with applicable federal and state regulations. The baseline also reflects practices operators must implement to comply with the self-implementing provisions in Section 114 of the PIPES Act of 2020. The analysis was conducted using a framework that considered pipeline mileage, the incidence and rate of detected leaks, miles surveyed at the required frequency, and the costs of surveys and repairs. Calculations were performed over a 15-year analysis period.

2.2.1. Mileage of Regulated Entities

In PRIA, PHMSA used the annual average changes over the 2015-2020 period to extrapolate onshore mileage through 2038. For Type C gathering lines, PHMSA used a previously developed estimate of the annual growth rate of 1.3 percent. PHMSA claimed the absence of specific data addressing Type C gas gathering pipelines data is publicly available in PHMSA website.

Table 1. Projected mileage of onshore gas gathering and gas transmission lines by year (miles)

Table 3: Projected mileage of onshore gas gathering and gas transmission lines by year (miles)					
Segment	Class	2021[1]	2026[1]	2031[1]	2036[1]
Gathering[2]	1	90,863	97,045	103,647	110,698
	2	7,280	9,026	10,979	13,046
	3	4,484	5,276	6,211	7,250
	4	14	21	28	34
	Total	102,641	111,368	120,864	131,029
Transmission	1	236,069	246,199	257,282	268,906
	2	30,495	31,806	33,196	34,635
	3	33,989	35,123	36,334	37,600
	4	868	879	890	901
	Total	301,421	314,006	327,703	342,042
Total		**404,062**	**425,374**	**448,567**	**473,071**

[1] PHMSA uses operator-specific annual mileage changes between 2015 and 2020 to project mileage for each year during the 2021-2038 period. As a result, total year-to-year mileage change may differ from that shown in Table 2 based on the aggregate mileage in each year.
[2] Includes regulated Type A, Type B, and Type C gas gathering lines.
Source: Gas Distribution Annual Report. Part B: System Description (6/1/2021 data release)

2.2.2. Methane Emissions

PHMSA estimates that methane emission reductions correspond to approximately 72 percent of unintentional emissions from regulated gathering pipelines. This metric was estimated in a simplified way without the use of modelling tools. The framework estimated avoided emissions based on the number of leaks detected mid-year (for leaks detected as part of a leak survey program requiring surveys two or more times per year) and cumulative emission reductions for leaks repaired in previous years, as these leaks would otherwise continue to emit methane. PHMSA assumes that all leaks detected as part of an annual leak survey program will be detected and repaired at the end of the year, with emissions reductions realized at the beginning in the following year. These calculations were done for both the baseline and proposed rule scenarios, with the difference between the two scenarios indicative of the benefits of the proposed rule. PHMSA considered incident data to estimate the number of leaks per mile (0.0253 leaks/mile-year for gas gathering lines) and CHGI emissions factors to estimate rates (288.5 kg/mile or 11.4 metric ton CH_4 per leak-year). The difference in mitigation from baseline was an effect of increased infrastructure scope (Type C gathering lines were included), increased inspection frequency and a higher number of leaks detected/repaired (they estimated effectiveness of 85% to leaks discoverable without ALD methods). PHMSA described that the leak incident rate is one of the sources of uncertainty since only a subset of leaks that occur each year are documented in annual reports due to the reporting criteria that focus on hazardous leaks and other leaks requiring repairs. As such, the leak incidence rate and other statistics derived from the reported data provide only a partial picture of existing leaks known to operators and/or repaired each year. These data are also subject to limitations of the respective detection or reporting thresholds or estimation methods.

In the section 3.4 and 6.2 from PRIA, PHMSA acknowledges that researchers have developed alternative methane emission estimates using either top-down or bottom-up assessments and compare values obtained from studies with the leak incident and emissions rates adopted. For gathering lines, two datasets are mentioned, but the main comparison is focused on results obtained in a study performed in the Permian by Chen et al. (2022). [1]This study estimated emissions attributable to pipelines at 29 ± 20 t/h. This estimate

[1] Chen et al. Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey Environmental Science & Technology 2022 56 (7), 4317-4323

is based on 175 leaks, which translates into an average rate of 166 kg CH_4/hr per leak. Based on the study, PHMSA calculated a leak incidence rate of 0.0188 leak/mile by considering the length of pipelines in the survey area (15,000 km) and assuming the survey was effective at detecting all existing pipeline leaks. For the study, pipeline emissions should come from a segment of the pipeline that is at least 200 meters (typical well pad diameter) away from any well sites, gas processing plant sites, compressor station sites, and storage tank sites. They evaluated that this number was consistent with and slightly lower than the incidence rate derived from PHMSA data (0.0253 leak/mile) and that the differences are most notable for emission rates. As such, using the findings from Chen et al. (2022) would not substantially change the number of leaks PHMSA estimated to be detected over time (and therefore the costs of making leak repairs) when compared to the main analysis but would significantly increase the benefits from avoided gas losses and methane emissions (covered in the sensitivity analysis). One of the problems this analysis presents is assuming that surveys performed in the study would be effective at detecting all existing pipeline leaks without evaluating the technology used to collect data. Chen et al. data was collected from aerial surveys performed by Kairos Aerospace and focused on evaluating medium-to-large point-source emissions; therefore, contributions of leaks with low rates are not included in the count of leaks per mile. Many studies have pointed out the characteristic heavy-tailed methane emissions distribution at oil and gas production sites. [2,3,4] If we assume that the same patterns apply to gathering lines, the consideration that leaks detected by Chen et al. represent all sources could result in a significant underestimation of the actual leak incidence rate. Finally, the analysis methodology does not allow for a cost-benefit analysis based on leak sizes, which would be essential to justify the strict technology requirements proposed in the rule.

2.2.3. Cost

Survey cost

PHMSA adopted a survey cost of $515 per mile, which reflects a combination of ground and aerial survey methods and ALD equipment. PHMSA 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 methods results in incremental costs on a per mile basis. For that reason, the same survey cost was considered for before (the baseline scenario) and after rule implementation. PHMSA recognizes that the assumption that unit costs are the same for both the baseline and regulatory scenarios may overstate the cost of conducting leak surveys using traditional survey methods, therefore underestimating the incremental costs of the proposed rule.

Industry feedback regarding survey cost adopted

Operators currently conducting aerial surveys with ALD equipment and on-foot leak surveys informed average costs based on their operations. The following table summarizes costs informed.

[2] Rutherford, J. S. et al. Closing the methane gap in US oil and natural gas production emissions inventories. Nat Commun 12, 4715 (2021).
[3] Omara, M. et al. Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate. Environ. Sci. Technol. 52, 12915–12925 (2018).
[4] Brandt, A. R., Heath, G. A. & Cooley, D. Methane Leaks from Natural Gas Systems Follow Extreme Distributions. Environ. Sci. Technol. 50, 12512–12520 (2016).

Table 2. Leak survey cost estimated by operators. The last column indicates the cost estimate used for the cost-benefit analysis.

Leak Survey Cost	Cost Estimative ($)	Cost used for cost-benefit analysis ($)	
Walking Survey w/ ADL instrument	80-150	120	per mile
High Sensitivity Aerial Survey	320	320	per mile
Low Sensitivity Aerial Survey	51-55	55	per mile
Follow-up	400	400	per follow-up

Repair Cost

The average unit repair cost used in the PHMSA analysis includes a unique estimate for leak repairs on transmission and gathering lines of $5,868/leak. This value was based on data supporting utility rate cases for transmission services (from Pacific Gas and Electric Company) and included the estimated cost of conducting a follow-up inspection to confirm the effectiveness of the repair ($218, based on 4 hours of technician's time).

Industry feedback regarding repair cost adopted

Operators informed Highwood that estimating leak repair costs is quite challenging due to the large variation in leak size and required steps to fix. For small repairs, a hot tap procedure to patch, installing a split sleeve, or other minimally invasive fixes could be possible. This may involve a reduction in pressure for a minimal time while the leak is repaired. An added advantage could be a limited or no blowdown of the pipeline. For medium repairs, a sleeve could be installed, or a more detailed repair process could be required, which may involve stopples. If a temporary isolation method near the leak is not feasible, a purge/blowdown of a segment of pipe between existing shutoff valves may be needed. Repair costs increase, along with operational impact, depending on shut-in period. For large repairs, contractors would conduct a cutout of several feet to ensure the section in question is completely removed. Again, isolation of a pipe length between stopples or existing block valves would occur, with a blowdown before the repair process would commence.

Based on the data informed by consulting with pipeline operators, Highwood calculated an average repair cost. For our analysis we considered that 90% of leaks identified would be small (grade 3), 9% would be medium (grade 2) and 1% would be large (grade 1). This results in an average repair cost of **$15,000 per repair.**

Table 3. Leak repair cost estimated by operators. The last column indicates the cost estimate used for the cost-benefit analysis.

Leak Type	Cost used for cost-benefit analysis ($)
Small (grade 3)	$10,000
Medium (grade 2)	$50,000

Large (grade 1)	$150,000

3. Monitoring Technologies

3.1. PHMSA Requirements Evaluation

The NPRM proposed by PHMSA introduced requirements for advanced leak detection programs (ALDPs), including establishing performance standards for both the sensitivity of leak detection equipment and the effectiveness of those ALDPs. According to the rule, the ALD devices must detect all leaks of 5 ppm or more when measured 5 feet from the pipeline and claims that the choice of leak concentration-based performance standard for leak detection equipment was informed by the goal of identifying a single performance standard that would be well-suited for leak detection on both aboveground and buried natural gas pipelines. PHMSA also claims that the 5-ppm performance standard balances each of the following: a methane sensitivity threshold consistent with the performance of state-of-the-art, commercially available technologies; robust margin to the risk of ignition; and flexibility for operators to choose from a baseline of high-quality equipment for their unique needs.

In the rule, PHMSA further explains that 1% of the lower explosive limit (LEL) of methane gas in the atmosphere is approximately 500 ppm, so a minimum sensitivity of 5 ppm (0.01% of LEL of natural gas) would therefore provide a protective threshold of detection sensitivity. This calculation was based on the LEL of natural gas of 5% (50,000ppm). It is important to consider that PHMSA did not quantify the safety benefits of the enhanced leak detection and repair requirements in the PRIA.

PHMSA also highlighted that some stakeholders attending the 2021 Public Meeting commented that leak flow rate would be a more appropriate metric for leak detection and ALDP program performance than PHMSA's proposed volumetric sensitivity metric, but no commenter provided a suggestion for how this could be implemented. PHMSA also highlighted that a concentration-based metric is especially useful for addressing explosion risks to public safety (regardless of the leak flow rate). Table 4 highlights some of the advanced leak detection options that could be used to meet requirements.

Table 4. Methane leak detection technologies. (Page 164)

Technology	Sensitivity	Range
Semiconductor	1-100 ppm	0-100 ppm
Flame Ionization	1 ppm	0-10,000 ppm
Open Path Infrared (IR) Tunable diode laser absorption spectroscopy	5 ppm-meter	0-100,000 ppm-meter
Closed Path Bifringent IR	1 ppm	0-2,500 ppm
Closed Path IR Laser	0.03-100 ppm	0-1000 ppm

Table 4 also informs the sensor sensitivity range; however, this information alone is not enough to address leak detection method performance. To understand the effectiveness of detection systems, it is critical to understand how those technologies are used, which goes beyond sensor specifications. Traditionally, those assessments are done through pilot projects or through sanctioned blinded studies at facilities like the Methane Emissions Technology Evaluation Center (METEC). Testing is used to derive a technology company's performance metrics like the probability of detection (usually as a function of leak rate and wind speed), the fraction of false positives, survey time and localization precision and accuracy.

Understanding technologies' performance for leaks from buried infrastructure is even more challenging, and studies in the area are limited. In a recent study, Tian et al. (2022a) used a dispersion-based model to calculate rates from measured methane mole fraction and compared the calculated rates to the known controlled NG release rates.[5] The study confirmed that measured methane mole fraction cannot be used to infer the size of a leak without considering the impacts of atmospheric stability conditions. This means that technology requirements based on mixing ratios is not the best approach when targeting emissions reductions. Another difficulty related to performance evaluation based on concentration is that this performance metric is not appropriate for widely adopted remote sensing technologies. For those two reasons, the industry should avoid setting requirements based on mixing ratios and distance and move into a demonstrated probability of detection of specified emission rates, which aligns with EPA proposed requirements.

The temporal variability was also evaluated recently by Tian et al. In this work, methane surface emissions concentration was calculated using dispersion modeling. The study showed a large temporal variability for the emission rates tested and demonstrated that at least 6 hours of data are needed to have a representative estimate from subsurface pipeline leaks (±27% of the controlled release rate on average). In the figure below the data collected is represented. Releases varied from 0.08-0.52 kg/hr. Of the releases performed, 0%, 12%, 16% and 24% of releases with rates of 0.08, 0.18, 0.27 and 0.52 kg/hr, respectively, had measured concentration above 5 ppm (considering increase above background). [6]

[5] Tian, S., Smits, K. M., Cho, Y., Riddick, S. N., Zimmerle, D. J. and Duggan, A. (2022a) Estimating methane emissions from underground natural gas pipelines using an atmospheric dispersion-based method. Elementa: Science of the Anthropocene.
[6] Tian, S., Smits, K. M., Cho, Y., Riddick, S. N., Zimmerle, D. J. and Duggan, A. (2022a) Estimating methane emissions from underground natural gas pipelines using an atmospheric dispersion-based method. Elementa: Science of the Anthropocene.

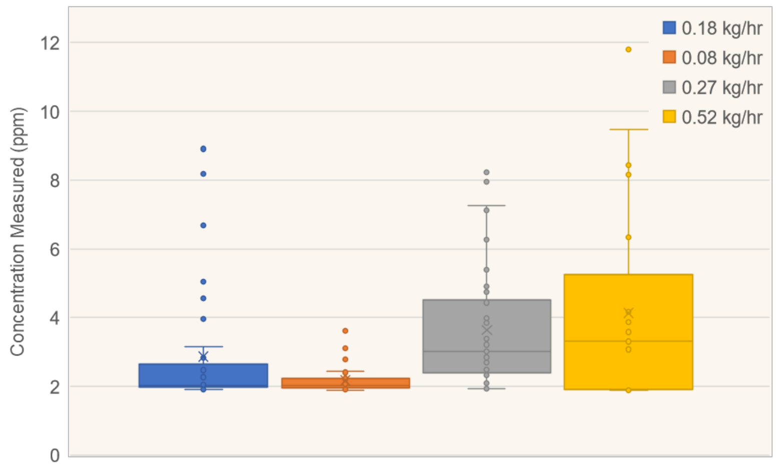


Figure 1. Concentration measurement according to release rate.

Another study by Tian et al. (2022b) also investigated the detection probability of mobile survey solutions for natural gas pipeline leaks under different atmospheric conditions and distances. [7] For this evaluation, methane concentrations were measured using a high-precision gas analyzer (GasScouter™ G4301, Picarro, Inc.), with 0.1 ppb measurement precision at a 1 Hz measurement interval. A pass was considered a detection if a 0.2 ppm methane mole fraction enhancement was observed over the 2.0 ppm background and controlled release rates varied from 0.03 – 0.51 kg/hr. Results showed probability of detection varied considerably depending on weather conditions(i.e., PG stability class and wind speed). According with derived model, considering mid-wind speed conditions (3m/s) the probability of detection can vary from 98% to 22% for 0.03 kg/hr releases, and from 99-46% for 0.51 kg/hr release depending on atmospheric stability class. The study also evaluated the impact of survey speed (driving or walking) and demonstrated that even when using a high-precision gas analyzer (that would meet the 5ppm at 5 ft requirement), the detection probability can vary significantly depending on how the technology is deployed and the environmental conditions. This highlights the importance of assessing technology performance based on probability of detection of specified emission rates.

We can draw the following takeaways from the studies:

- A ppm standard measurement cannot be translated into a reasonable flow-rate-based equivalent and should not be used to infer the size of a leak without considering the impacts of atmospheric stability conditions.
- When using point sensors, data should be collected close to the source and for a long period of time (hours) to achieve reasonable leak rate estimates.

[7] Tian, S., Riddick, S. N., Cho, Y., Bell, C. S., Zimmerle, D. J. and Smits, K. M. (2022b) Investigating Detection Probability of Mobile Survey Solutions for Natural Gas Pipeline Leaks Under Different Atmospheric Conditions. Environmental Pollution.

- Considering walking surveys only, a device meeting PHMSA's requirements has a high probability (>80% chance) of detecting leaks from 0.03 – 0.51 kg/hr at most atmospheric conditions.

3.2. Current Landscape

Various studies have shown that methane measurement technologies differ significantly in accuracy, precision, and resolution, thus generating vastly different information that can be used to answer distinct questions. Many of these technologies face environmental and operational limitations, where performance depends significantly on whether the objective is detection, localization, or quantification. Monitoring pipelines is especially problematic because very few commercially available technologies have the sensitivity and spatial coverage required and are cost-effective at the same time. In addition, most of the various methods available are new, and their potential roles for monitoring methane emissions remain poorly understood. Therefore, controlled release testing, field deployment, and cost assessment studies are still necessary to guide decisions on how those technologies or combinations of technologies compare. This report will group methane measurement technologies into six categories:

- **Handheld instruments**: Close-range instruments that include handheld OGI cameras, organic vapour analyzers approved under U.S. EPA Method 21, and new LiDAR-based instruments.
- **Aircraft and helicopters:** Gas detection sensors are fit for light aircraft and helicopters. A range of sensor types and deployment modes are used from entire regions to individual sites.
- **Unmanned Aerial Vehicles:** Gas detection devices are fit for drones, which are suitable for rapidly surveying individual facilities, or for flying pipeline right of way.
- **Mobile ground labs:** Passenger vehicles with gas detection equipment. In situ, gas detectors are mostly used and require the truck to physically drive through methane plumes.
- **Satellites:** Low Earth Orbit satellites that detect large methane plumes. Most methane-sensing satellites measure entire regions at low spatial resolution. Some emerging satellites claim to have the resolution to target individual sites.
- **Continuous measurement devices:** Methane detection units that are installed at a facility to enable continuous monitoring of methane emissions as they evolve over time.

In this report we will not cover continuous measurement systems and satellites in further detail. Continuous monitoring excels in capturing emissions data at a very fine temporal scale. However, they are bound to a given facility, and costs can be high, especially in the absence of strong regulatory drivers, which could make them more appealing over high-frequency handheld surveying requirements. Satellites can cover vast swaths of ground quickly, but their detection limits are more than an order of magnitude higher than the expected detection limits achieved by devices that meet PHMSA requirements.

These technology categories are often subdivided based on their sensing principle, which refers to the general approach to methane detection. Sensing principles can be split into three categories:

- **Point measurement**: involves directly measuring methane mixing ratios in the atmosphere, which requires the sensor to be positioned in a plume to discern anomalies above the background.

- **Passive imaging**: involves the measurement of electromagnetic energy that is naturally reflected or emitted by the environment. Typically, methane's interaction with infrared (IR) light is visualized and/or measured using spectroscopy.
- **Active imaging:** Involves emitting an energy source and measuring the signal intensity reduction of that source due to absorption by the target gas. For methane measurements, a laser with a specific wavelength is used as an energy source.

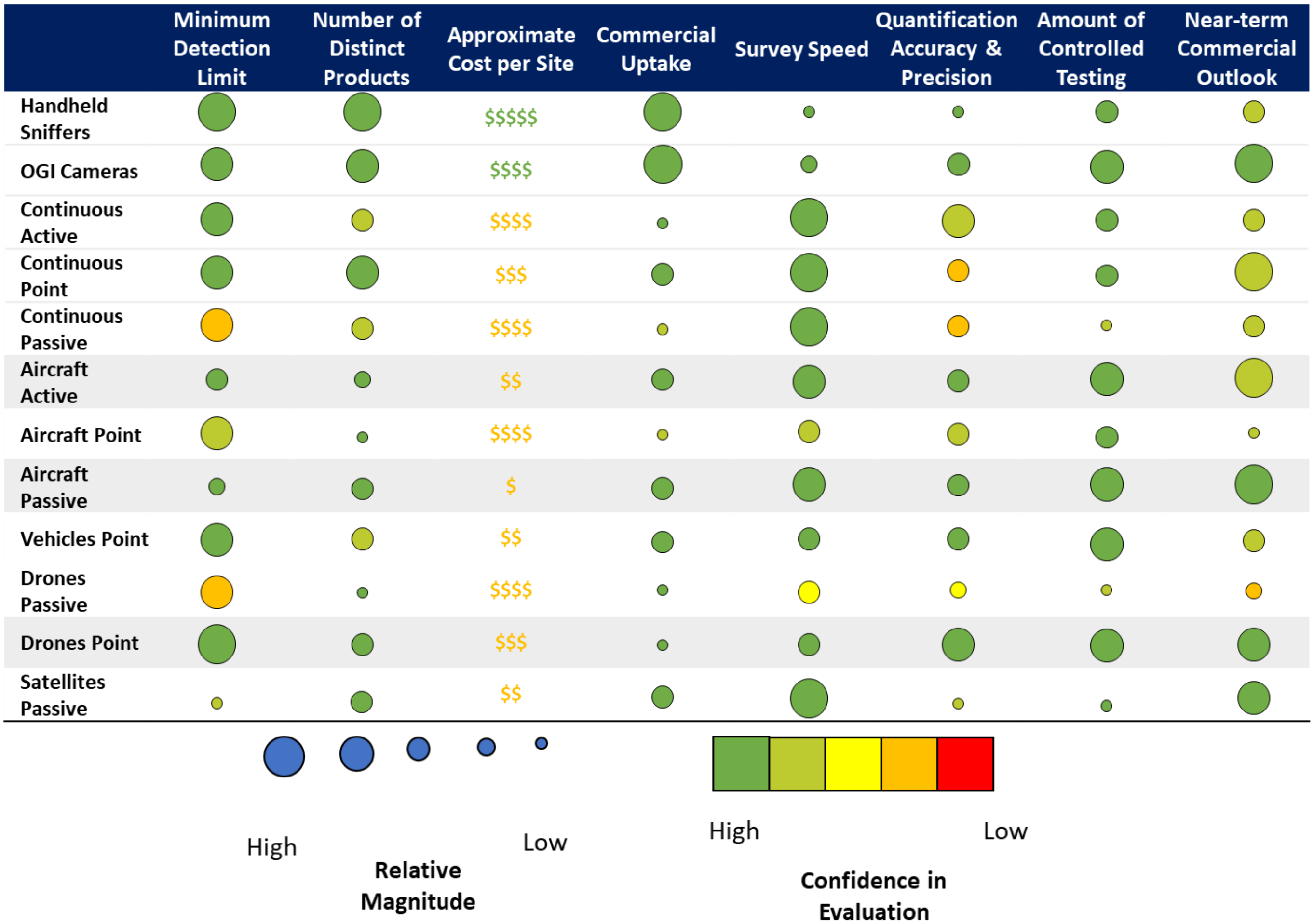
Before focusing on them, it is important to define some relevant terminologies used in this report:

- **Mixing ratio vs emission rate:** Mixing ratio gives the proportion of air that is methane, usually in parts per million (ppm) or billion (ppb), while the emission rate reports how much methane (mass or volume) or natural gas that emits from a source per unit time.
- **Detection vs quantification:** Detection typically involves the determination that mixing ratios or emission rates constitute an anomaly above the background, while quantification estimates the emission rate of a source. Typically, quantification involves atmospheric dispersion modelling using localization estimates, mixing ratios, and weather.
- **Sensitivity:** Ability of a method to detect low emission rates.

3.3. Qualitative technologies comparison

Table 5 provides a qualitative comparison of detection technologies available based on publicly available data. More details about suitable technologies for pipeline monitoring are provided in the following sections.

Table 5 - Qualitative technologies comparison.



3.4. Aircraft and helicopters

Aircraft systems have seen the most significant uptake among alternative solutions. Their main advantages are speed and height, which lead to high spatial coverage and lowered costs. Depending on infrastructure density, aircraft are capable of surveying hundreds to thousands of sites or hundreds of miles of pipeline per day. In North America, many operators are moving to adopt those advanced solutions for detecting methane emissions from pipelines.

While there is evidence that LDAR surveys using handheld devices are effective in reducing fugitive emissions, they often fail to detect intermittent, high-emission events that can disproportionately contribute to total methane emissions.[8] An aerial survey of oil and gas sites in Northern British Columbia completed using the Bridger Photonics Gas Mapping LiDAR (GML) technology in September 2019 revealed a significant difference in the aerial and OGI methane inventory (1.6-2.2X greater), suggesting that policy and

[8] Xia, H., Strayer, A., & Ravikumar, A. (2023). The Role of Emissions Size Distribution on the Efficacy of New Technologies to Reduce Methane Emissions from the Oil and Gas Sector.

regulations relying on handheld devices alone may risk missing a significant portion of emissions. A comparison of data from OGI and aerial surveys shows that most of the time, there is little overlap with the detected sources, so combining both methods present an opportunity for a more holistic understanding of methane emissions.

Passive and active imaging aircraft systems have seen the highest uptake, and both have been independently tested in several studies. In terms of disadvantages, most aircraft systems struggle to detect small leaks and are sensitive to environmental conditions. Due to the lower sensitivity, the mitigation equivalency with handheld devices may require surveys to be performed more frequently depending on technology minimum detection limit and emissions profiles. The impact of emissions profiles was recently described by Xia et al. in a study that demonstrated the complex trade-off between technology choice and survey frequency.

Established manufacturers and service providers
Bridger Photonics, Kairos Aerospace, LaSen, Flyscan, GHGSat-AV, Pergam Technical Services, Scientific Aviation.

Reported Performance

Technology	Performance	Source
Bridger	Controlled release testing demonstrates a 90% probability of detection at 0.25 kgh/mps at 500m altitude or 0.41 kgh/mps at 675m altitude	Footnote [9]
Kairos	During controlled release testing Kairos detected 100% of emissions above 15 kgh/mps. The smallest release detected was 8.3 kgh/mps.	Footnote [10]

3.5. Unmanned Aerial Vehicles

UAVs are drones equipped with sensors that are flown manually by pilots around areas of interest, including O&G infrastructure. Currently, the most promising UAV systems use point measurement with tunable diode laser absorption spectroscopy (TDLAS) sensors. Passive imaging measurement technologies in UAVs are less common. In general, drones equipped with OGI cameras have not been shown to be effective, and interest in industry interest is low. To our knowledge, the only existing OGI-mounted drone solution worth noting is the Baker Hughes LUMEN drone, which claims to combine OGI with TDLAS. Unfortunately, Baker Hughes has not published field trials or controlled release testing results and distributed very little information on how the system works.

[9] Clay Bell, Jeff Rutherford, Adam Brandt, Evan Sherwin, Timothy Vaughn, Daniel Zimmerle; Single-blind determination of methane detection limits and quantification accuracy using aircraft-based LiDAR. Elementa: Science of the Anthropocene 4 January 2022; 10 (1): 00080.
[10] Evan D. Sherwin, Yuanlei Chen, Arvind P. Ravikumar, Adam R. Brandt; Single-blind test of airplane-based hyperspectral methane detection via controlled releases. Elementa: Science of the Anthropocene 21 January 2021; 9 (1): 00063.

UAVs are becoming more popular, and as more testing and data validation are performed, the technology potential will grow, but current commercial uptake is still low. Deployment costs depend on work practice, and the greatest cost savings can occur through flight automation, but this option does not yet exist. The primary limitations are weather, the distance from the operator (typically, the UAV must be in the line of sight of the pilot, as per most regulations), and the relatively short flight times of a few minutes to a few hours. Aboveground controlled release testing to evaluate minimum detection limits for UAVs suggests that they can be below 15-20 g CH_4/h, much lower than most other technologies. For pipeline leak surveys, drones" platforms are promising alternatives to complement close-range methods due to advantages such as not needing roads to operate and the ability to reach dangerous or inaccessible places. However, additional work is needed to properly benchmark critical performance metrics for buried infrastructure, such as minimum detection limits under different conditions.

Established manufacturers and service providers
SeekOps (TDLAS), ABB, Avitas, Pergam Technical Services, SkySkopes.

Reported Performance

Technology	Performance	Source
SeekOps	100% POD for leaks > 1SCFH *(Testing performed for leaks from aboveground infrastructure)*	Footnote 11
SkySkopes	MDL = 0.07 g/s	Footnote 12
ABB	100% POD for leaks > 8 SCFH *(Testing performed for leaks from aboveground infrastructure)*	Footnote 11
Baker Hughes	100% POD for leaks > 8 SCFH *(Testing performed for leaks from aboveground infrastructure)*	Footnote 11
Picarro (in a drone)	100% POD for leaks > 8 SCFH *(Testing performed for leaks from aboveground infrastructure)*	Footnote 11
Advisian	100% POD for leaks > 3-5 SCFH *(Testing performed for leaks from aboveground infrastructure)*	Footnote 11

3.6. Mobile ground labs

Mobile ground labs (MGLs) consist of vehicles equipped with methane sensors and GPS units. They are a versatile platform that generates a map of methane concentrations along the vehicle path. The traditional survey method requires MGLs to be stationed within the plume of interest while measurements are made.

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[11] Ravikumar et al. Single-blind inter-comparison of methane detection technologies – results from the Stanford/EDF Mobile Monitoring Challenge. Elementa: Science of the Anthropocene 1 January 2019; 7 37.
[12] Li, H.Z.; Mundia-Howe, M.; Reeder, M.D.; Pekney, N.J. Gathering Pipeline Methane Emissions in Utica Shale Using an Unmanned Aerial Vehicle and Ground-Based Mobile Sampling. Atmosphere 2020, 11, 716.

However, newer, less-precise methods use in-motion quantification. Currently, only point measurement systems exist in the market, and measurements must be made from within the gas plume. Commonly used sensors include Picarro systems, Li-COR 7700 TDLAS, and LGR systems. Passive MGL measurements could theoretically be made by mounting instruments, such as OGIs, on vehicles performing unrelated tasks. However, little to no interest or movement exists, partly due to the cost of OGI cameras and the complications of driving with them at high speeds. Road access and wind direction are the primary limitations and restrictions of this technology class. Commercial uptake is low but potentially increasing, and the cost is on the medium-low end of the cost scale.

Established manufacturers and service providers
Picarro, University of Calgary (PoMELO), ABB, GeoVerra, Aeris Technologies, Heath Consultants

Reported Performance

Technology	Performance	Source
PoMELO	100% POD for rates as low as 0.00158 g/s *(Testing performed for leaks from aboveground infrastructure)*	Footnote 13
Aeris	100% POD for leaks > 5-8 SCFH *(Testing performed for leaks from aboveground infrastructure)*	Footnote 14
Health Consultants	100% POD for leaks > 8 SCFH *(Testing performed for leaks from aboveground infrastructure)*	Footnote 14

3.7. Close-range instruments

The most common are OGI cameras and portable handheld instruments (used to comply with M21 requirements). Close-range methods have several advantages, such as providing intuitive results, they are familiar (already widely in use), they are written into the regulations (low risk) and being sufficiently sensitive. The primary limiting factor for handheld devices is the highly labour-intensive nature of the operation. Typically, Method 21 operators can survey 500 components per day. Depending on the number of miles, full surveys could take days to months to complete.

Established manufacturers and service providers:
Honeywell, Heath Consultants, Sensit – handheld
Opgal, FLIR, GreenPath Energy, Montrose Environmental Group – OGI Cameras

Reported Performance

[13] University of Calgary Rapid Vehicle-based Methane Emissions Mapping System (PoMELO) Single-Blind Testing Results from the Methane Emissions Technology Evaluation Center (METEC)

[14] Ravikumar et al. Single-blind inter-comparison of methane detection technologies – results from the Stanford/EDF Mobile Monitoring Challenge. Elementa: Science of the Anthropocene 1 January 2019; 7 37. doi: https://doi.org/10.1525/elementa.373

Technology	Performance	Source
OGI	29.6 SCFH (90% POD) – 0.158 g/s experienced operators – 11 SCHF – 200g/h (0.059g/s) *(Testing performed for leaks from aboveground infrastructure)*	Footnote 15
Gas Sniffer (GasScouter™ G4301, Picarro, Inc.)	> 80% POD for rates – 0.03 - 0.51 kg/hr under most atmospheric conditions.	Footnote 16

4. Emissions Reduction Modeling

4.1. Methodology

Exploratory modelling was conducted to identify whether the leak detection performance required by PHMSA is necessary to achieve significant emissions reductions and explore whether the sensitivities of existing technologies are sufficient. In the following sections, a brief description of the LDAR-Sim framework and relevant parameters will be provided before diving into the modelling results.

4.1.1. LDAR-Sim background

LDAR-Sim operates by constructing a "virtual world" of Oil and Gas facilities to which fugitive emissions and fugitive emission mitigating programs are applied. Each day in the simulation can be split into three parts: adding new leaks, finding leaks, and repairing leaks. During a simulation, leak detection surveys are carried out by virtual crews. Behaviour such as travel speed, survey speed, and environmental, operational windows, is parametrized to be representative of real-world performance. A high-level infographic depiction of what happens when LDAR-Sim is run is shown in Figure 2.

[15] Zimmerle et al , Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions Environmental Science & Technology 2020 54 (18), 11506-11514
[16] Tian, S., Riddick, S. N., Cho, Y., Bell, C. S., Zimmerle, D. J. and Smits, K. M. (2022) Investigating Detection Probability of Mobile Survey Solutions for Natural Gas Pipeline Leaks Under Different Atmospheric Conditions. Environmental Pollution. In Press.

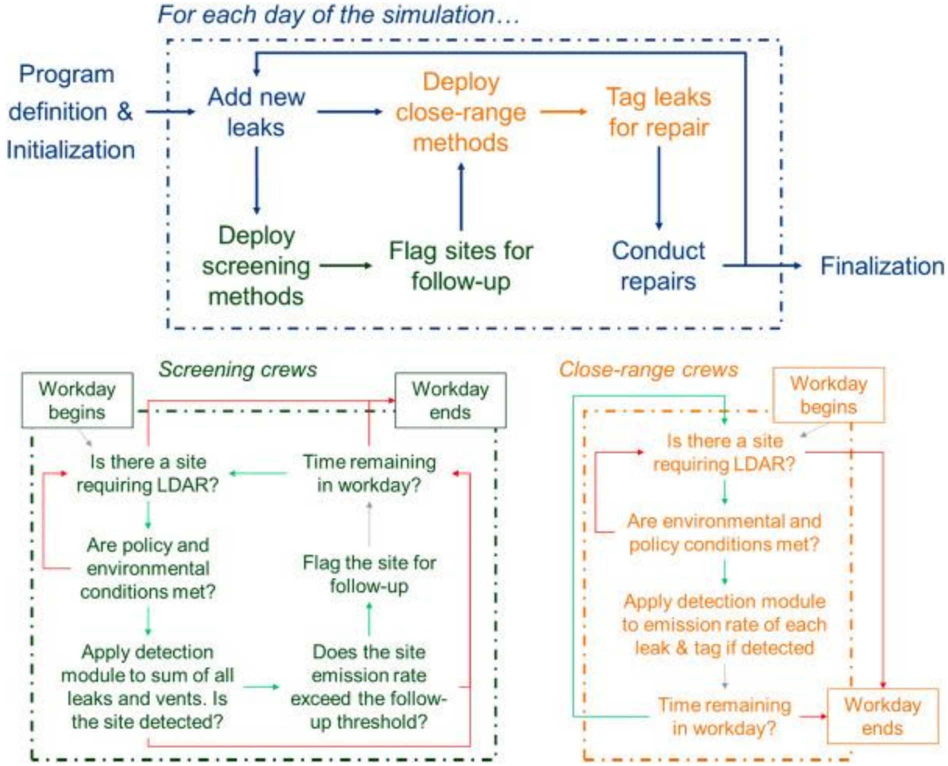

Figure 2. Overview of LDAR-Sim routine. Green text is used for screening methods, and orange text for close-range methods.

4.1.2. Relevant Parameters

The most relevant parameters used in the modelling are described in the following list. This is a summarized version focused on important parameterizations to interpret simulation modelling results.

- **Infrastructure:** The infrastructure file informs the facilities included in the simulation and required survey frequencies. The infrastructure adopted was based on PRIA assumptions described in section 2.2.1 of this report.
- **Leak Rates:** These inputs dictate the simulated leak sizes (emission rates) generated in the modelling environment. Currently, studies providing information around leak rate distributions for gathering lines are limited, and for that reason, multiple scenarios were evaluated to guide decision-making around the sensitivity required to achieve mitigation goals. Leak rate distributions used in this study are further discussed in section 4.1.3.
- **Leak Production Rate (LPR):** This parameter dictates the probability that a fugitive emission will arise at a pipeline facility on a given day. For exploratory modelling, the LPR was parametrized depending on the distribution adopted. For distributions 1 and 2, the PHMSA incident rate was applied, which considers 0.0253 leaks/mile-year. For distribution 3 (based on Chen et al.), the LPR observed in the study was considered, which was 0.0188 leak/mile.
- **Minimum Detection Limit**: The smallest methane emission rate a particular technology can detect. For PHMSA programs, it was assumed that the technology used would be able to detect all leaks

higher than 0.03 kg/hr (based on peer-reviewed studies described in section 3.1). To evaluate the mitigation achieved by screening technologies with higher detection limits, additional programs with minimum detection limits of 1 kg/hr, 4 kg/hr, 10 kg/hr and 30 kg/hr were tested. Those levels were chosen based on detection tiers proposed for advanced leak detection technologies in the EPA NPRM.

- **Spatial coverage**: A representation of the average proportion of leaks that a method can effectively survey. In practice, every time a new leak is created, a "weighted coin" is flipped, representing the methods' spatial coverage. If the method "loses" the weighted coin flip, it will not detect that emission and will not be able to do so on subsequent screenings or surveys. The modelling conducted for this report assumed coverage of 100% for all methods, besides the PHMSA baseline, which was modelled with 85% coverage (following PRIA's assumption that only 85% of leaks would be detected when surveys are performed without leak detection devices).
- **Repair Delay**: Time that a leak exists from tagging to repair. LDAR-Sim does not have the functionality to assign repair timelines according to leak sizes. Therefore, we assumed that most leaks detected would be classified as grade 2 (> 10 SCFH) and would be repaired in 6 months.
- **PHMSA costs**: PHMSA estimated a leak survey cost of $515 per mile. Assuming that this represents an average of 10 miles surveyed per day (considering on-foot surveys), the cost per day would be $5150/day. Highwood estimated that after screenings, a maximum of two closer-range follow-ups could be performed by day, leading to a cost of $2,575 per follow-up inspection. Cost estimated by operators are described in section 2.2.3.

4.1.3. Leak Rate Distributions

LDAR-Sim modelling relies on leak rate distributions to inform the size (rate) of leaks added to the simulation, and the chosen leak rate distribution used has a marked impact on simulation results. It is important to consider that depending on the basin being represented, differing leak rate distributions might be expected. Unfortunately, for gathering systems, very few datasets are available for an accurate representation.

The mitigation achieved in a theoretical basin dominated by large emissions will be less impacted by performing screening with technologies with higher minimum detection limits, while basins prone to smaller leaks might be more affected. To explore the impact of leak rate distributions in simulation results, Highwood modelled LDAR program equivalency using three leak rate distributions:

Distribution 1: An "augmented" version of equipment leak data distribution used for fugitive emission modelling conducted to support the EPA Methane Emissions Regulations Proposal. The "augmented" distribution used in LDAR-Sim was augmented with leaks observed by Chen et al. with the objective of including a 1% contribution of medium to large leaks, which were not represented in the original distribution.[17] This scenario represents the assumption that most leaks will be considerably small with a small portion of super emitters.

[17] Coburn, J. & Stott, R. Modeling Fugitive Emissions from Production Sites Using FEAST.

Distribution 2: An empirical leak rate distribution based on Zavala-Araiza, 2015 which is built from bottom-up and top-down measurements of emissions from sites in the Barnett Shale.[3] This distribution is often used in LDAR-Sim modelling to represent basins prone to "medium to small" emissions, unlike those typically seen in the Permian basin. This is an intermediate scenario where small, medium and large leaks are present.[18]

Distribution 3: A leak rate distribution based on emission rates recorded for gathering lines reported by Chen et al. Leak data was recorded from aerial surveys performed by Kairos Aerospace in the Permian Basin and focused on evaluating medium-to-large point-source emissions. Therefore, contributions of leaks with low rates are not represented in this distribution. This is the most extreme scenario, focused on regions where large leaks are more frequent.[19]

The leak rate distributions used are shown as cumulative density functions in Figure 3.

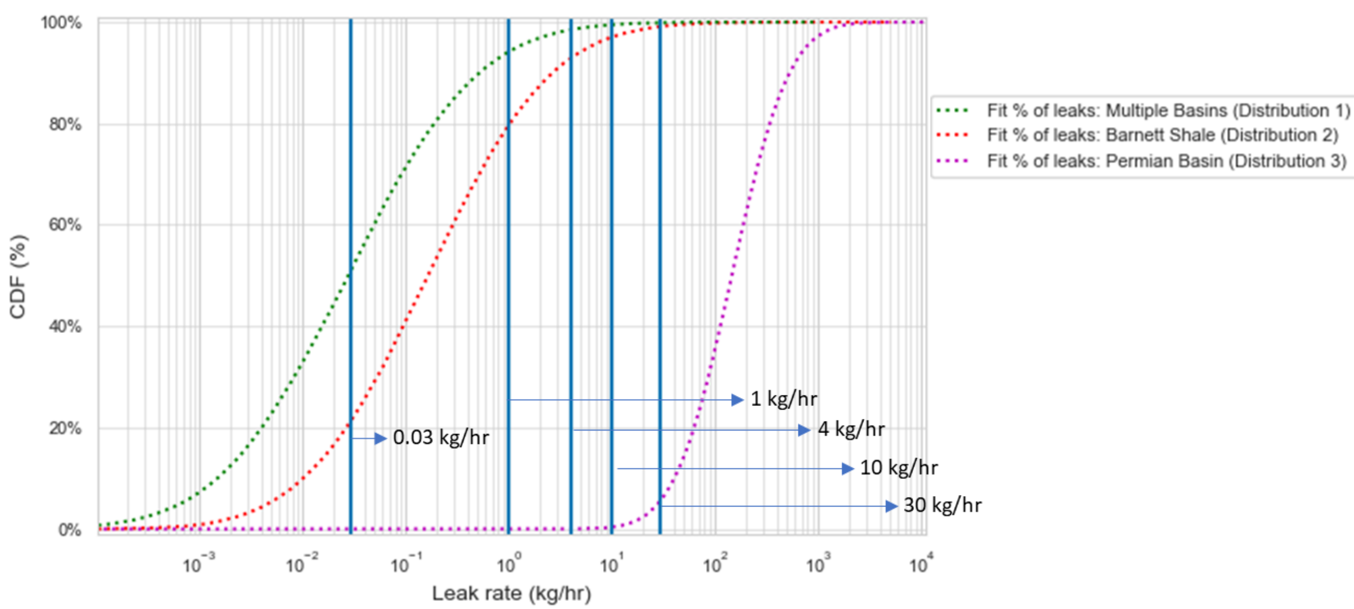

Figure 3. Cumulative distribution function of emission data from peer-reviewed empirical studies used to inform leak sizes in LDAR-Sim modelling. "Fit % of Leaks" (dotted lines) refers to the proportion of individual leak sizes in each distribution. For example, when referring to the" Leaks" CDF of Distribution 2, we see that 20% of individual leaks in the distribution are 0.03 kg/hr or smaller.

It is important to highlight that the data used to create Distribution 1 (based on EPA modelling data) represents leaks observed at production sites. This dataset was used due to the limited bottom-up measurements of gathering leaks.

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18 Zavala-Araiza, D. et al. Reconciling divergent estimates of oil and gas methane emissions. Proc. Natl. Acad. Sci. U.S.A. 112, 15597–15602 (2015).
19 Chen et al. Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey Environmental Science & Technology 2022 56 (7), 4317-4323

4.2. Results and Discussion

4.2.1. Programs Nomenclature

A naming style was adopted to help identify the different programs evaluated. The following list describes the nomenclature adopted for each modelling scenario.

PHMSA programs

- P_PHMSA: Program based on PHMSA proposed requirements. Includes a close-range method with a 0.03 kg/h minimum detection limit with 100% spatial coverage deployed to the entire infrastructure following survey frequency requirements.
- *P_PHMSA baseline:* Program based on PHMSA proposed requirements. Includes a close-range method with 0.03 kg/h minimum detection limit with 85% spatial coverage deployed to infrastructure currently regulated (does not include Type C gathering lines) following current survey frequency requirements. Non-regulated sites are not surveyed, so emissions from those sites are not identified and repaired. Consequently, emissions build faster in this program throughout the 5 years evaluation.

Screening Programs

- P_XXXkgh_YY: Program based on screening methods with follow-up inspections. XXX represents the minimum detection limit of the technology employed, and YY indicates the survey frequency. For programs named with YY = 1x, the proposed rule frequency was followed. For program names with YY= 2x, frequency requirements were doubled. The program assumes that all leaks flagged by the screening method will be tagged in a follow-up survey performed with a close-range instrument.

4.2.2. Distribution 1 modelling results (facilities prone to smaller leaks)

In the upcoming sections, we will delve into the simulation results considering Distribution 1. Figure 4 illustrates the overall emissions mitigation achieved by each program over a 5-year period. Table 6 presents specific information on the annual number of miles surveyed, accounting for frequency requirements, follow-up actions, and repairs completed. It should be noted that LDAR-Sim currently lacks the capability to model variations in infrastructure throughout the evaluation period. Consequently, the mitigation results assume that the 2021 gathering lines infrastructure (section 2.2.1) remains unchanged during the assessment. In the PRIA assessment, a yearly increase of approximately 2% was factored in to estimate increase in cost and mitigation; however, we are confident that this increment will not significantly impact the comparison of outcomes among the programs.

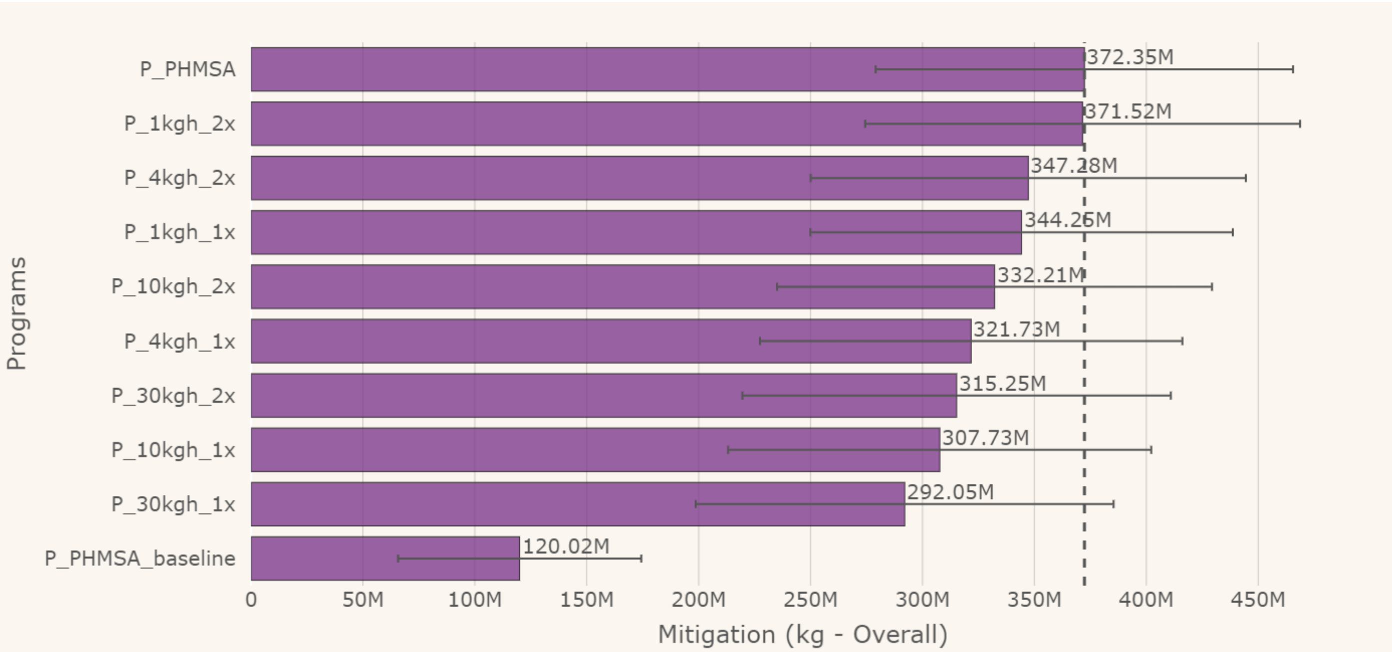


Figure 4. Emission mitigation achieved by exploratory programs during 5 years of deployment when leak rates are informed by Distribution 1 (representative of basins prone to smaller leaks). Programs were named based on the minimum detection limit of the screening technology and frequency (section 4.2.1). High variability was observed between simulation rounds due to the presence of super emitters. Capital M indicates 1 thousand metric tons of CH_4 (100,000 kg).

Table 6. Modelling outputs when leak rates are informed by Distribution 1. The table details the number of miles surveyed per year, considering frequency requirements and follow-up and repairs completed per year. Leak survey, follow-up and repair cost per year considering PHMSA assumptions (costs described at the bottom) are also included. The Estimative considers the 2021 gathering lines infrastructure(section 2.2.1).

Program	Leak Surveys (miles)	Follow-ups Surveys (per year)[1]	Repairs (per year)	Leak Survey Cost ($/year)	Follow-up Cost ($/year) [1]	Repair Cost ($/year)	Total[2] ($/year)
P_PHMSA_ baseline	36,640	0	361	19MM	-	2.04MM	21MM
P_PHMSA	107,167	0	1349	55MM	-	7.62MM	63MM
P_1kgh_1x	107,167	151	151	55MM	0.39MM	0.85MM	56MM
P_1kgh_2x	214,334	151	151	110MM	0.39MM	0.85MM	112MM
P_4kgh_1x	107,167	43	43	55MM	0.11MM	0.24MM	56MM
P_4kgh_2x	214,334	43	43	110MM	0.11MM	0.24MM	111MM
P_10kgh_1x	107,167	21	21	55MM	0.05MM	0.12MM	55MM

P_10kgh_2x	214,334	21	21	110MM	0.05MM	0.12MM	111MM
P_30kgh_1x	107,167	12	12	55MM	0.03MM	0.07MM	55MM
P_30kgh_2x	214,334	12	12	110MM	0.03MM	0.07MM	110MM

1. Applicable only for screening programs
2. Sum of leak survey, follow-up, and Repair cost per year. Cost estimated considering pipeline infrastructure in 2021.
3. Cost was estimated considering $515/mile for leak surveys (no differentiation between technologies), $2750 per follow-up and $5650 per repair.

Key takeaways:

- The program following PHMSA requirements achieved the highest cumulative mitigation (~372 thousands metric ton of CH_4 in 5 years) but also presented an excessively high number of repairs. Alternatively, screening programs performed at the same frequency also achieve significant mitigation but requiring a small number of repairs. If we compare P_PHMSA with P_1kgh_1x, we can see that mitigation in five years dropped 8% but the number of required repairs per year was reduced by 89% (from 1349 to 151 repairs). This reinforces the importance of addressing large sources to achieve mitigation goals.

- Considering PHMSA cost estimates, leak surveys represented the major cost. However, it is important to consider feedback from operators around leak survey cost being overestimated and repair cost being underestimated. Later in this section, we include a detailed cost-benefit analysis incorporating operator's feedback, which changes how impactful both(leak survey and repair) are to the annual cost. The repair cost is also highly impacted by the leak incidence assumption (repair cost increase directly correlates with how many leaks are added to the system per year), which is an important source of uncertainty in this analysis. As previously mentioned in section 2.2.2, there is strong evidence that the leak incidence assumed is underrepresenting leaks per year.

- For this distribution the survey frequency has a small impact on overall mitigation. Doubling the frequency have a small impact on overall mitigation but doubles program cost per year. For example, comparing P_1kgh_1x with P_1kgh_2x we increase mitigation from 344 to 321 thousand metric ton of CH_4 in 5 years, which represents a 7% increase, while the cost increases from $56MM per year to $112 per year, which represents a 100% increase. This small effect on mitigation happens because in this scenario leaks are generally small and not as frequent when compared with typical production sites. The long repair timelines (6 months to repair a leak after tagging it) also impact on frequency impact.

- PRIA assumed an average value for all types of technology and considerably low repair costs. When we replicated those here, we can see that PHMSA program (with a lower minimum detection limit) exhibits the highest cost, but it also achieves the most significant mitigation, resulting in an appealing mitigation cost (measured in $ per kilogram of methane avoided). However, a more comprehensive cost-benefit analysis considering operator feedback around cost for specific technologies and adjusted repair costs shed further light on this scenario, which will be discussed later in this section.

Detailed cost-benefit analysis incorporating operator's feedback

In the following analysis the results from modeling were used to estimate programs costs and benefits depending on the technology used. For this analysis 3 different programs were considered. The MDL adopted represent the one where most of the technologies from a specific class would fit in our previous matrix. The three programs consider PHMSA survey frequency.

- **Walking Surveys**: Based on P_PHMSA modelling outputs
- **Aerial Survey (High Sensitivity)**: Based on P_4kgh_1x modelling outputs
- **Aerial Survey (Low Sensitivity)**: Based on P_30kgh_1x modelling outputs

In the first analysis, annual costs, considering infrastructure variation, were estimated from 2021 up to 2038. (Figure 5). The annual cost includes the sum of leak survey cost, follow-up (when applicable) and repair. Cost per mile, per follow-up and per repair reflect operator's feedback is described in section 2.2.3.

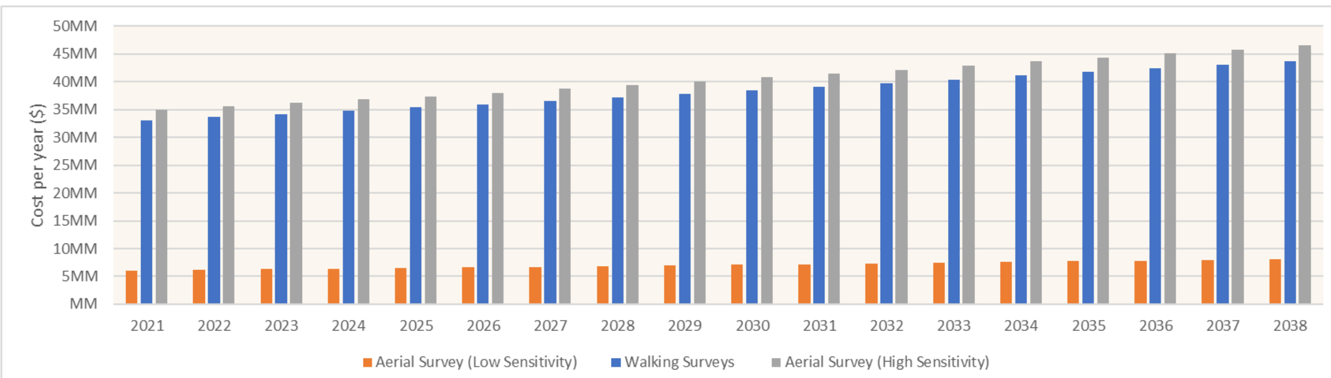


Figure 5. Annual costs for multiple programs considering infrastructure variation. Cost per year includes leak survey cost, follow-up (when applicable) and repair. Cost per mile, per follow-up and per repair reflect operator's feedback is described in section 2.2.3.

In Figure 5 we can notice that *walking* and *aerial (high sensitivity)* surveys had the highest cost. For aerial surveys (high sensitivity) the elevated cost is highly impacted by elevated cost of flyovers ($320/mile) and for walking surveys a significant cost portion comes from the excessively high number of repairs. This is illustrated In Figure 6 (scenario A), where the cumulative cost for a 5-years deployment was broken down by leak survey cost (including follow-ups) and repairs.

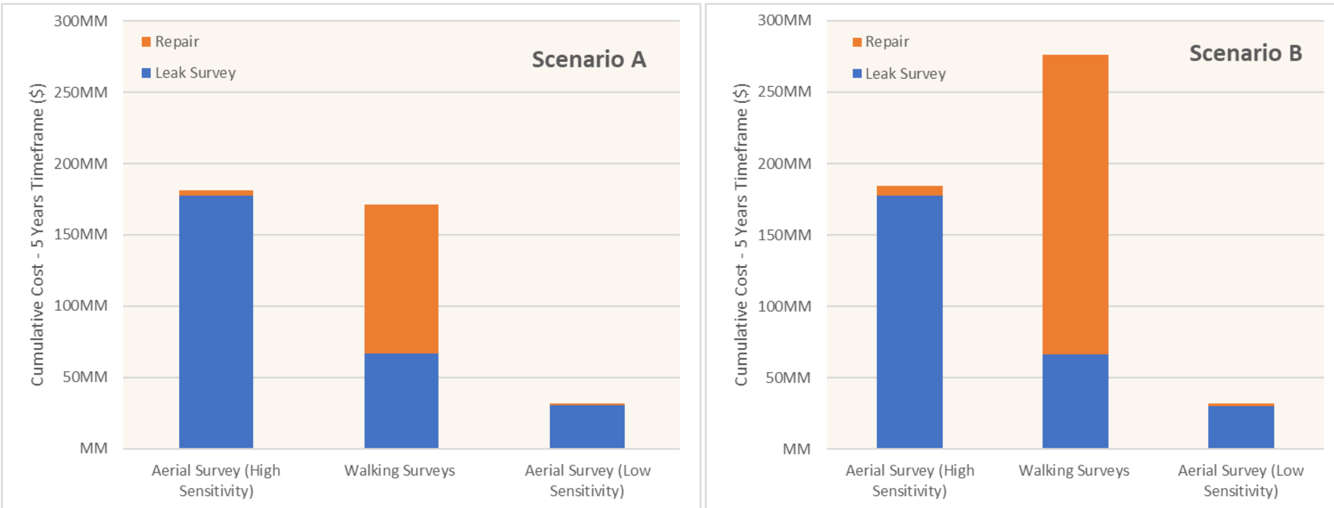


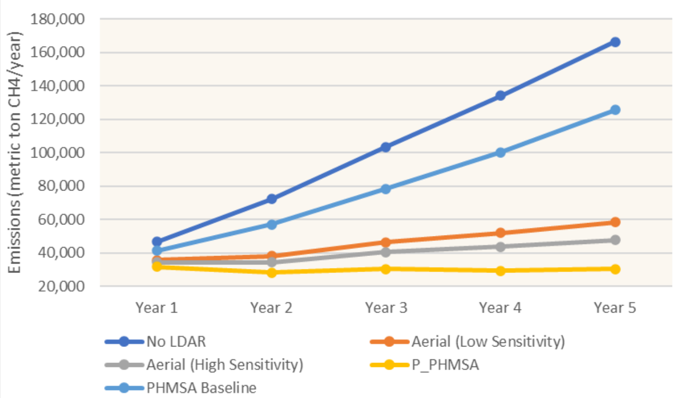
Figure 6. Cumulative cost for a 5-year deployment broken down by leak survey cost (including follow-ups) and repairs. Scenario A represents costs considering the PHMSA leak incidence rate assumption, and Scenario B considers the cost if the leak incident rate was multiplied by 2.

As mentioned earlier, the uncertainty surrounding leak incidence has a significant impact on repair costs. For this analysis, we are adopting the PHMSA assumption, which suggests approximately 2.5 leaks per year every 100 miles. This estimation was derived from the PHMSA incident database and assumes that leaks identified by operators without using leak detection equipment account for 85% of the total leaks. Although we lack data from studies estimating the number of leaks that sensitive instruments (required by PHMSA) would detect, there is compelling evidence that the total number of incidents is higher. To highlight the influence of this assumption, we introduced an additional scenario (Scenario B) considering a higher leak incidence rate (twice the initial assumption). Figure 6 demonstrates that the increased leak incidence considerably impacts the cost of walking surveys, making it the most expensive program among the three.

Finally, in Figure 7, we compared cost and emissions mitigation to understand which program can bring more value with fewer resources. On the left side, we have a time-series showing how much emissions increase year-by-year for each program, and on the right side, we have the mitigation cost (calculated by the ratio of 5-year cumulative cost by 5-year cumulative mitigation). The main takeaways from Figure 7 are:

- Even tough mitigation decreases when using less sensitivity technologies (mitigation against no LDAR program drops from 72% to 56%), aerial (low sensitivity) surveys is still the most cost-effective solution for gathering lines inspections.
- Walking surveys would be the second most cost-effective solution considering repair and survey costs only. However, its mitigation cost is close to aerial surveys (high sensitivity), which have other advantages besides cost. For example, aerial surveys are safer for personnel (less driving time) and less impactful on the supply chain (fewer repairs required but significant mitigation).
- The cost of false positives resulting from the use of overly sensitive technology was not assessed in this study but would also impact the cost of walking surveys.

Program	Mitigation (%) against no LDAR	Mitigation (%) against baseline
Aerial (Low Sensitivity)	56%	43%
Aerial (High Sensitivity)	62%	50%
Walking Survey	71%	63%



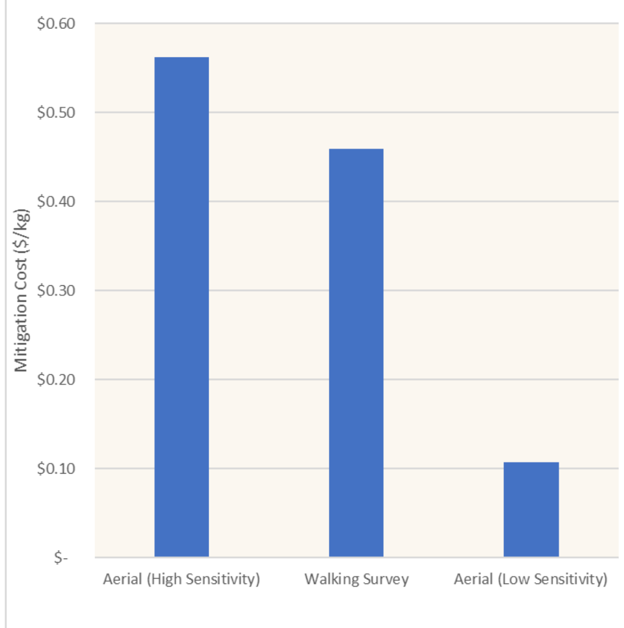


Figure 7. Left side, modelled emissions per year when considering Distribution 1. Right side, mitigation cost ($/ kg of CH4 avoided - calculated considering cumulative 5-year cost and cumulative 5-year mitigation).

4.2.3. Distribution 2 modelling results (facilities prone to mid-size leaks)

In the following sections, simulation results when Distribution 2 is considered are detailed. In Figure 8 overall emissions mitigation achieved by each program considering a 5-year deployment is compared. In Table 7 details around number of miles surveyed per year, considering frequency requirements, and follow-up and repairs completed per year are described.

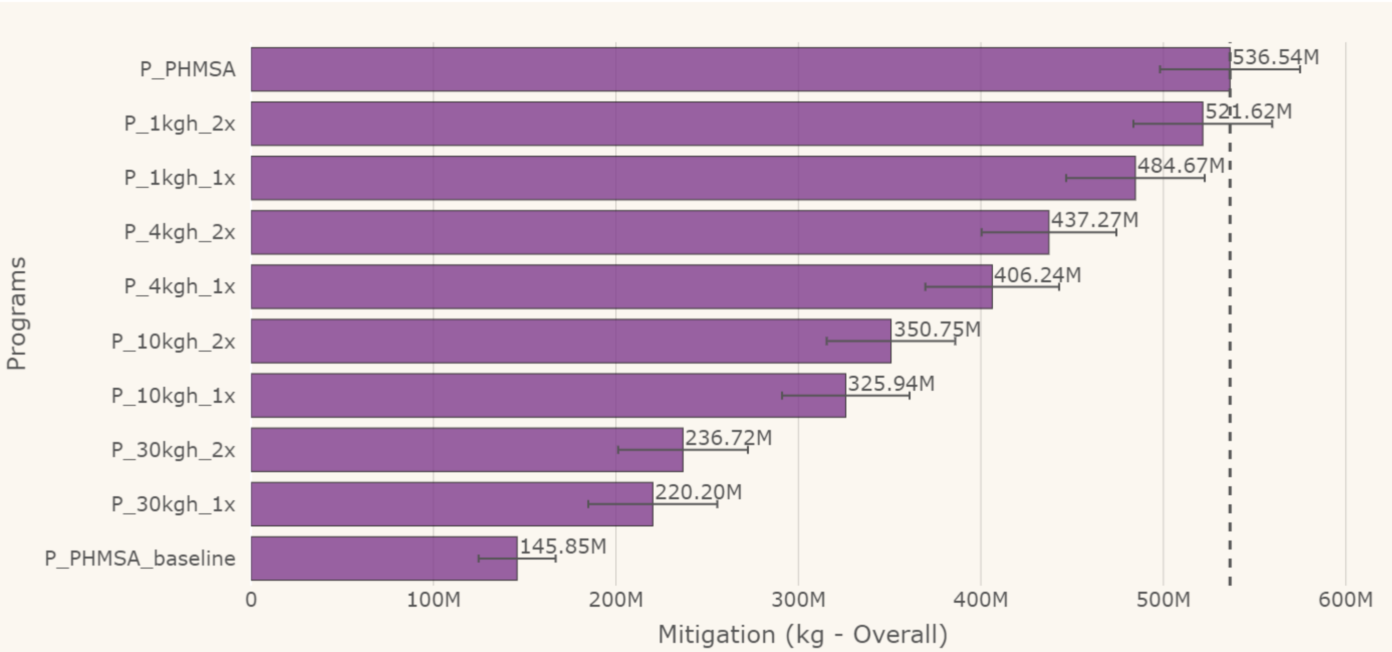


Figure 8. Emission mitigation achieved by exploratory programs during 5 years of deployment when leak rates are informed by Distribution 2 (representative of basins prone to mid-size leaks). Programs were named based on the minimum detection limit of the screening technology and frequency (section 4.2.1). Capital M indicates 1 thousand metric tons of CH_4 (100,000 kg).

Table 7. Modelling outputs when leak rates are informed by Distribution 2. The table details the number of miles surveyed per year, considering frequency requirements and follow-up and repairs completed per year. Leak survey, follow-up and repair cost per year considering PHMSA assumptions (costs described at the bottom) are also included. The Estimative considers the 2021 gathering lines infrastructure(section 2.2.1).

Program	Leak Surveys (miles)	Follow-ups Surveys (per year)[1]	Repairs (per year)	Leak Survey Cost ($/year)	Follow-up Cost ($/year) [1]	Repair Cost ($/year)	Total[2] ($/year)
P_PHMSA_ baseline	36,640	0	580	19MM	-	3.28MM	22MM
P_PHMSA	107,167	0	2194	55MM	-	12.40MM	68MM
P_1kgh_1x	107,167	559	559	55MM	1.44MM	3.16MM	60MM
P_1kgh_2x	214,334	558	558	110MM	1.44MM	3.15MM	115MM
P_4kgh_1x	107,167	200	200	55MM	0.51MM	1.13MM	57MM
P_4kgh_2x	214,334	200	200	110MM	0.51MM	1.13MM	112MM
P_10kgh_1x	107,167	81	81	55MM	0.21MM	0.46MM	56MM
P_10kgh_2x	214,334	81	81	110MM	0.21MM	0.46MM	111MM

P_30kgh_1x	107,167	22	22	55MM	0.06MM	0.13MM	55MM
P_30kgh_2x	214,334	22	22	110MM	0.06MM	0.13MM	111MM

1. Applicable only for screening programs
2. Sum of leak survey, follow-up, and Repair cost per year. Cost estimated considering pipeline infrastructure in 2021.
3. Cost was estimated considering $515/mile for leak surveys (no differentiation between technologies), $2750 per follow-up and $5650 per repair.

Key takeaways:

- Again, PHMSA requirements achieved the highest mitigation but also led to an excessively high number of repairs. If we compare P_PHMSA with P_1kgh_1x, we can see that mitigation dropped from 537 to 485 thousand metric tons (about 10%), but the number of required repairs was reduced by 75% (from 2194 to 559 repairs).
- Due to the distribution evaluated (mid-size leaks), more leaks are detectable by PHMSA and screening technologies, increasing the average number of repairs per year and reducing the gap in the number of repairs between PHMSA and P_1kgh_1x in terms of cost.
- The variability between rounds of simulation is smaller, and mitigation achieved by less sensitive tiers starts to become important (significant mitigation drop compared to PHMSA). Leak surveys continue to represent the major cost when PHMSA assumptions are considered.
- Again, the survey frequency has a small impact on overall mitigation. Doubling the frequency have a small impact on overall mitigation but doubles program cost per year.

Detailed cost-benefit analysis incorporating operator's feedback

A similar analysis performed for distribution 1 was repeated for the modelling round considering distribution 2. Figures 9-11 contain the main results, and key takeaways are included at the bottom of the section.

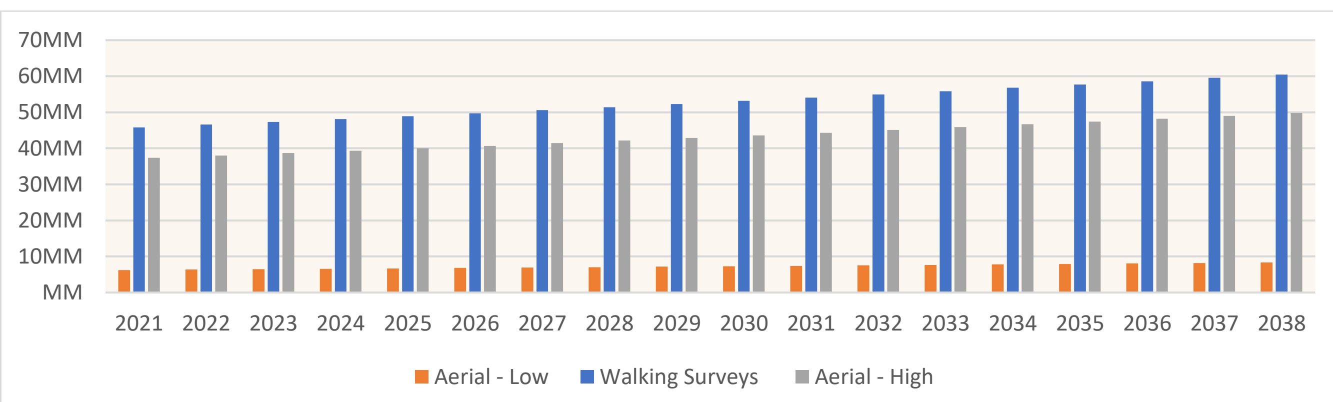


Figure 9. Annual costs for multiple programs considering infrastructure variation. Cost per year includes leak survey cost, follow-up (when applicable) and repair. Cost per mile, per follow-up and per repair reflects the operator's feedback described in section 2.2.3.

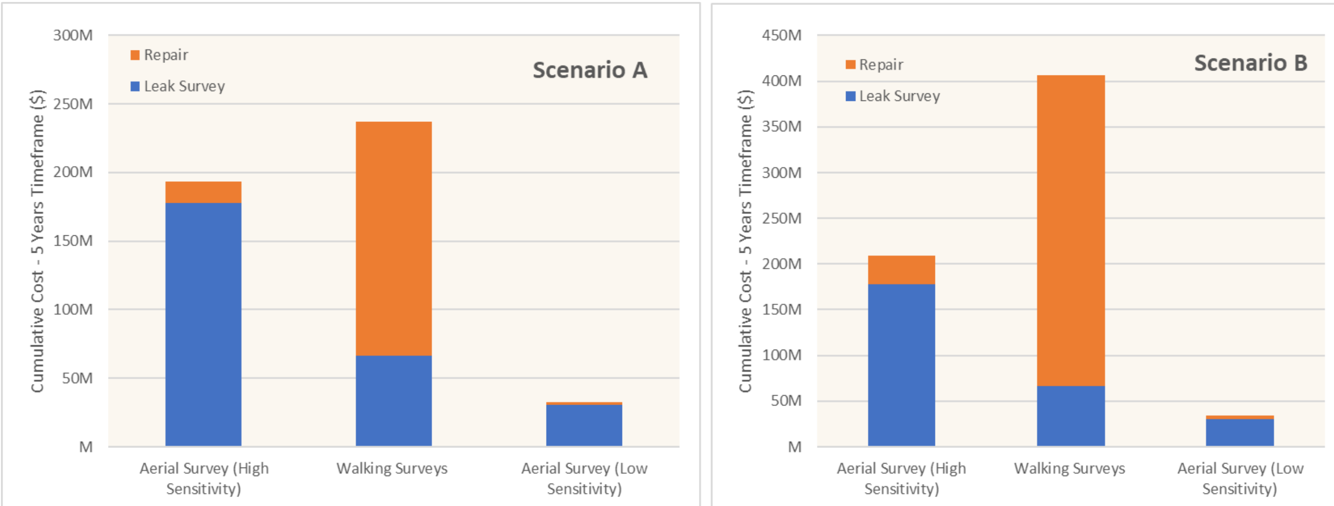
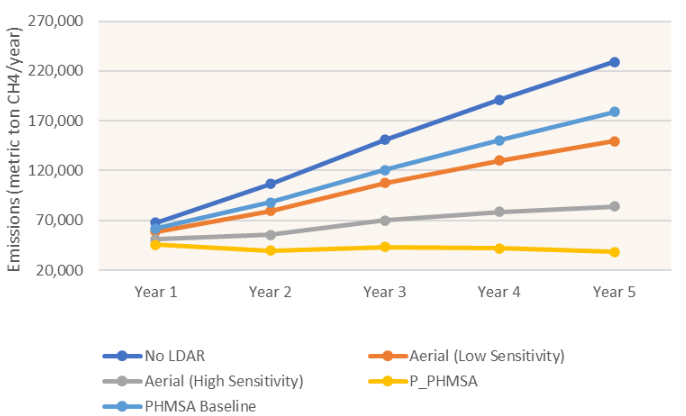


Figure 10. Cumulative cost for a 5-years deployment broken down by leak survey cost (including follow-ups) and repairs. Scenario A represents costs considering PMSA leak incident assumption and Scenario B consider cost if leak incident was multiplied by 2.

Program	Mitigation (%) against no LDAR	Mitigation (%) against baseline
Aerial (Low Sensitivity)	30%	12%
Aerial (High Sensitivity)	55%	43%
Walking Survey	72%	65%



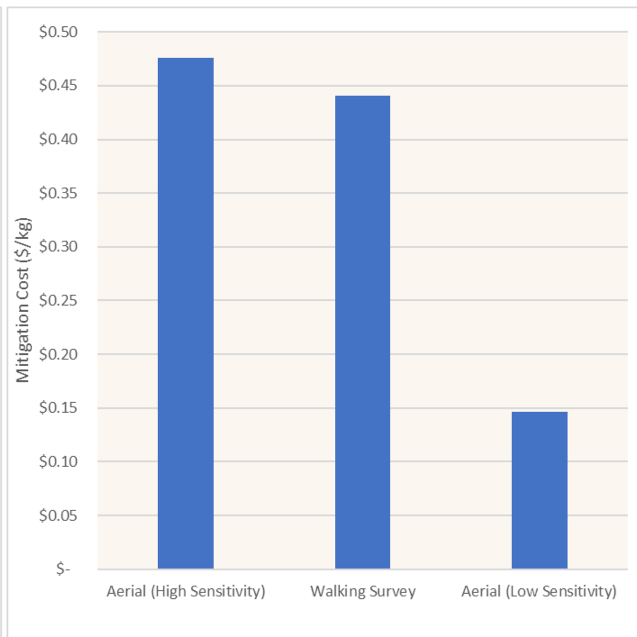


Figure 11. Left side, modelled emissions per year when considering Distribution 2. Right side, mitigation cost ($/ kg of CH4 avoided - calculated considering cumulative 5-year cost and cumulative 5-year mitigation)

Key takeaways:

- When a larger distribution is considered, we have a lower portion of leaks being missed by the technologies (see section 4.1.3), which considerably impacts the cost of repairs. However, a similar trend is observed for total cost – aerial surveys (low sensitivity) have the lowest annual and cumulative cost and best mitigation cost than the other two programs.

- However, the leaks missed by aerial surveys (low sensitivity) have a considerable rate and are more impactful to overall mitigation. Considering mitigation related to the no LDAR program, mitigation drops from 72% (walking surveys) to 30% (aerial low sensitivity).
- For basins with leak profiles similar to distribution 2, aerial surveys with higher sensitivity might be required to achieve mitigation goals. For this case mitigation drops from 72% (walking surveys) to 55% (aerial high sensitivity).
- Again, aerial surveys (high sensitivity) demonstrate the highest mitigation cost but are safer to personnel (less driving time) and less impactful on the supply chain (fewer repairs required but significant mitigation). Those are also less impacted by uncertainty around leak incident rate because they focus on major and important leaks (Figure 10b).

4.2.4. Distribution 3 modelling results (facilities prone to large leaks)

In the following sections, simulation results when Distribution 3 is considered are detailed. In Figure 12, the overall emissions mitigation achieved by each program considering a 5-year deployment is compared. In Table 8, details around number of miles surveyed per year, considering frequency requirements, and follow-up and repairs completed per year are described.

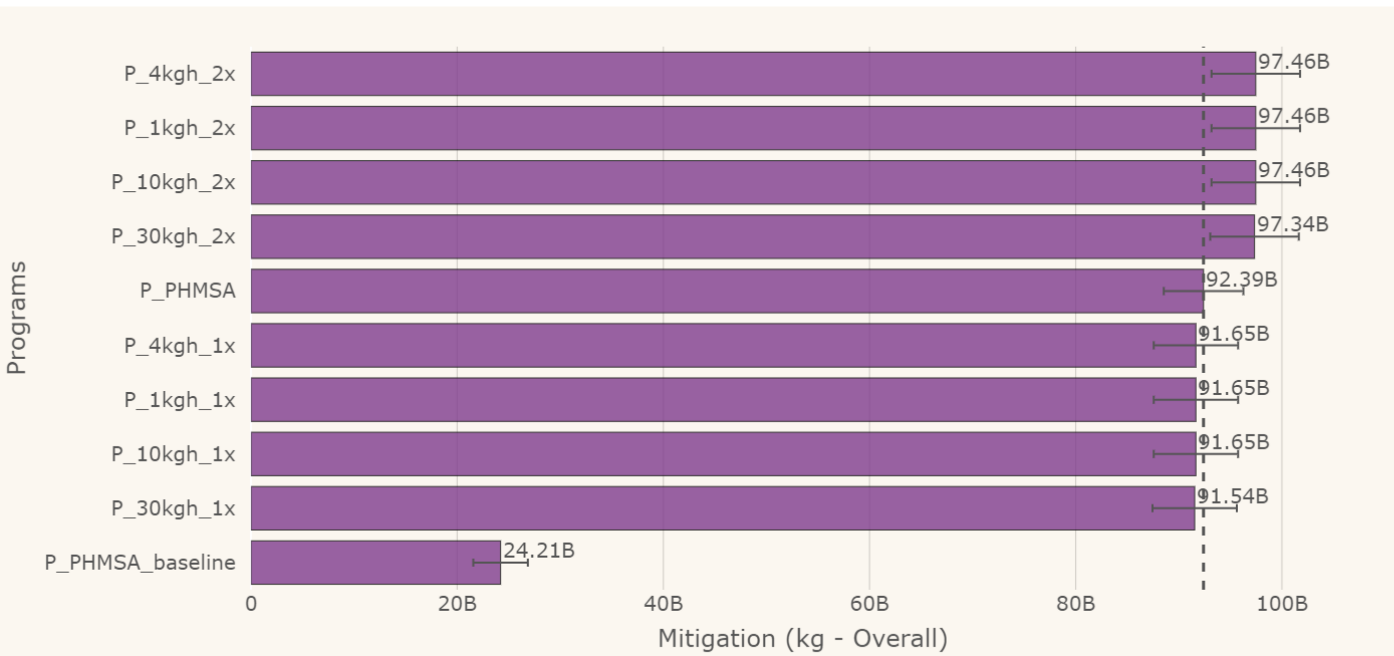


Figure 12. Emission mitigation achieved by exploratory programs during 5 years of deployment when leak rates are informed by Distribution 3 (representative of basins prone to large leaks). Programs were named based on the minimum detection limit of the screening technology and frequency (section 4.2.1). Capital B indicates 1 million metric tons of CH_4 (1,000,000,000 kg).

Table 8. Modelling outputs when leak rates are informed by Distribution 3. The table details the average number of repairs and follow-ups required, total cost, mitigation % achieved, and mitigation cost for all programs evaluated

Program	Leak Surveys (miles)	Follow-ups Surveys (per year)[1]	Repairs (per year)	Leak Survey Cost ($/year)	Follow-up Cost ($/year) [1]	Repair Cost ($/year)	Total[2] ($/year)
P_PHMSA_ baseline	36,640	0	585	19MM	-	3.31MM	22MM
P_PHMSA	107,167	0	2209	55MM	-	12.48MM	68MM
P_1kgh_1x	107,167	2187	2187	55MM	5.63MM	12.36MM	73MM
P_1kgh_2x	214,334	2181	2181	110MM	5.62MM	12.32MM	128MM
P_4kgh_1x	107,167	2187	2187	55MM	5.63MM	12.36MM	73MM
P_4kgh_2x	214,334	2181	2181	110MM	5.62MM	12.32MM	128MM
P_10kgh_1x	107,167	2187	2187	55MM	5.63MM	12.36MM	73MM
P_10kgh_2x	214,334	2181	2181	110MM	5.62MM	12.32MM	128MM
P_30kgh_1x	107,167	2140	2140	55MM	5.51MM	12.09MM	73MM
P_30kgh_2x	214,334	2134	2134	110MM	5.49MM	12.06MM	128MM

1. Applicable only for screening programs
2. Sum of leak survey, follow-up, and Repair cost per year. Cost estimated considering pipeline infrastructure in 2021.
3. Cost was estimated considering $515/mile for leak surveys (no differentiation between technologies), $2750 per follow-up and $5650 per repair.

Key takeaways:

- When a distribution containing only mid to large leaks is considered, the frequency starts to play a significant role. For this round of simulation, double frequency led to the highest mitigation than the PHMSA program.
- In this case, most leaks added to the system are large enough to be detected by all screening programs, so we do not observe a significant variation in the total number of repairs between programs. It is important to highlight this is a scenario where small leaks portion are not represented in the distribution.
- Data used to inform this emissions scenario was collected in the Permian region (Chen et al.), showing that for this specific region, sensitive technologies are not required to achieve mitigation goals.

- Even in this scenario where a higher number of repairs is required, repairs are still not the major cost source when PHMSA cost estimates are considered. A different scenario is observed in the detailed cost-benefit analysis incorporating the operator's feedback.

Detailed cost-benefit analysis incorporating operator's feedback

A similar analysis performed for distribution 1 was repeated for the modelling round considering distribution 3. Figures 13-15 contain the main results, and key takeaways are included at the bottom of the section.

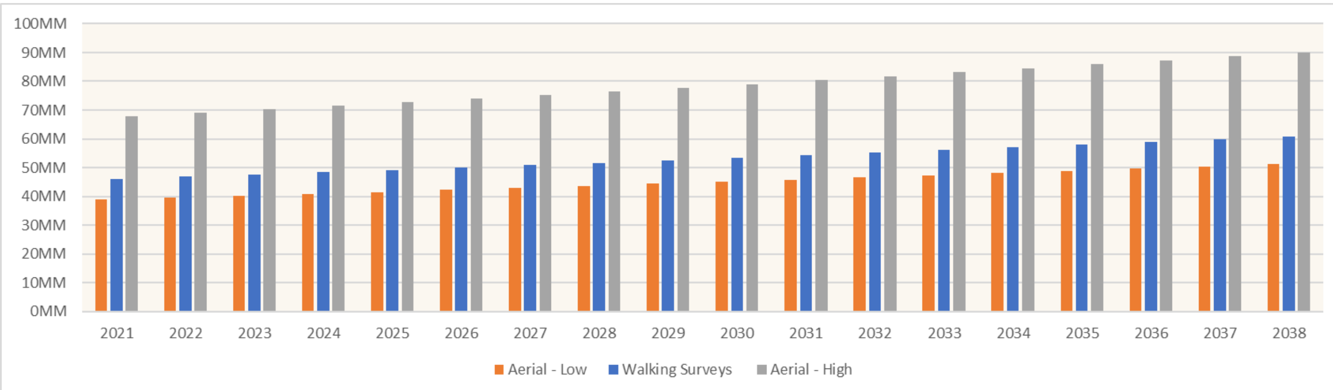


Figure 13. Annual costs for multiple programs considering infrastructure variation. Cost per year includes leak survey cost, follow-up (when applicable) and repair. Cost per mile, per follow-up and per repair reflects the operator's feedback described in section 2.2.3.

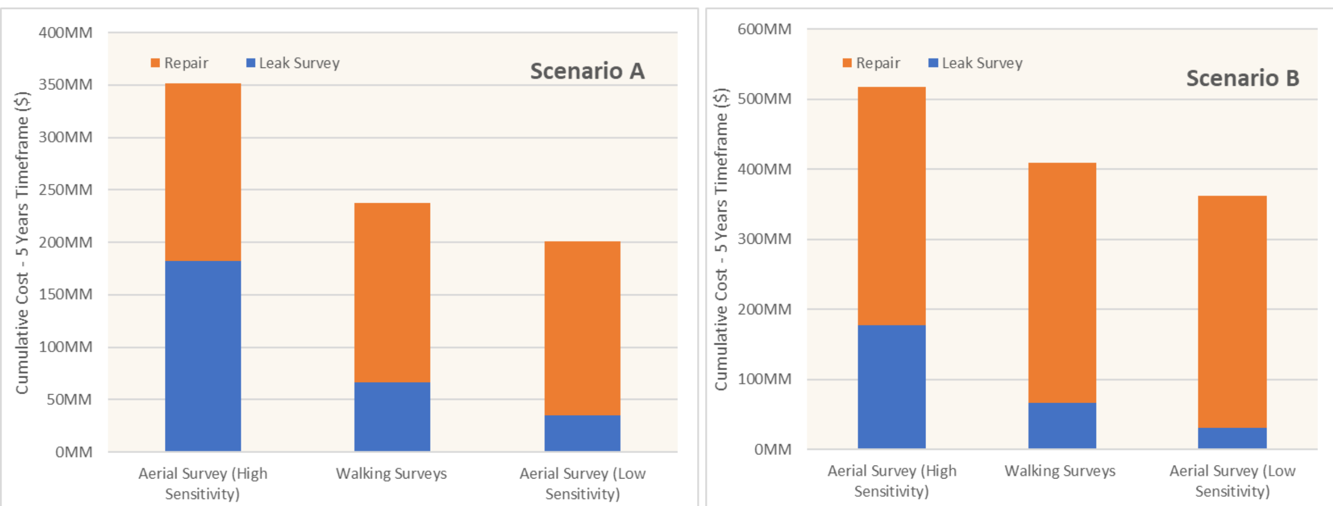
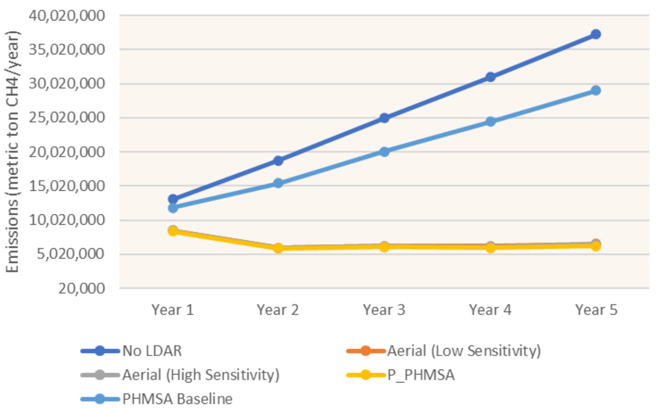


Figure 14. Cumulative cost for a 5-year deployment broken down by leak survey cost (including follow-ups) and repairs. Scenario A represents costs considering the PMSA leak incident assumption, and Scenario B considers the cost if the leak incident was multiplied by 2.

Program	Mitigation (%) against no LDAR	Mitigation (%) against baseline
Aerial (Low Sensitivity)	73%	67%
Aerial (High Sensitivity)	73%	67%
Walking Survey	74%	68%



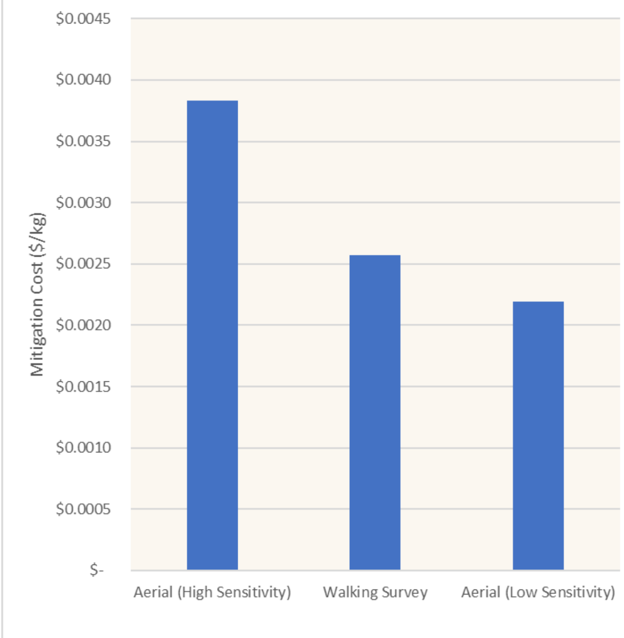


Figure 15. Left side, modelled emissions per year when considering Distribution 3. Mitigation achieved by Aerial (low and high sensitivity) and P_PHMSA overlap in the plot.Right side, mitigation cost ($/ kg of CH_4 avoided - calculated considering cumulative 5-year cost and cumulative 5-year mitigation)

Key takeaways:

- When a larger distribution is considered, we have an even lower portion of leaks being missed by the technologies (see section 4.1.3), which considerably impacts the cost of repairs. For this scenario, repair represents a major program cost.
- All major leaks are detected through aerial surveys (low and high sensitivity), and similar mitigation Is achieved by aerial and walking surveys. Considering mitigation related to the no LDAR program, mitigation drops from 74% (walking surveys) to 73% (aerial low and high sensitivity).
- For basins with leak profiles similar to distribution 3, aerial surveys with low sensitivity can achieve significant mitigation because the contribution of large sources is responsible for most emissions.
- Again, aerial surveys (low sensitivity) demonstrate the lowest mitigation cost.

5. Conclusions

- The utilization of concentration-based technology requirements by PHMSA cannot be used to estimate leak size without considering atmospheric stability conditions.
- When considering walking surveys, devices meeting PHMSA requirements have a high probability (>80% chance) of detecting leaks ranging from 0.03 to 0.51 kg/hr under most atmospheric conditions. While unmanned aerial vehicles and mobile ground labs have the potential to achieve the desired performance range, commercially available aircraft-based technologies generally lack the necessary sensitivity to meet requirements. Additionally, the framework that will be considered for technology approval is not clear.
- Limited datasets are available regarding leak incident rates and leak rates from gathering lines. Nevertheless, the evaluation of different scenarios has demonstrated that higher detection limit technologies can still achieve substantial emissions reductions without requiring a substantial increase in the number of required repairs. The optimal detection limit will vary based on the specific leak profiles in each basin. However, across all cases studied, a threshold of 4 kg/hr has proven to strike a balance between effective mitigation and the number of required repairs. Technologies that can demonstrate this performance are more expensive and increase the mitigation cost, but bring additional befits such as increased safety.
- Uncertainty around leak incident rate has an important impact on repair costs and must be considered carefully when accessing the cost of different programs. There is strong evidence that the total number of leaks per year is being underestimated. A higher leak incident rate will have a significant impact on PHMSA program cost and a lower effect on screening programs with higher detection limits.