DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191, 192, and 193

[Docket No. PHMSA–2021–0039]

RIN 2137–AF51

Pipeline Safety: Gas Pipeline Leak Detection and Repair

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: PHMSA proposes regulatory amendments that implement congressional mandates in the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 to reduce methane emissions from new and existing gas transmission pipelines, distribution pipelines, regulated (Types A, B, C and offshore) gas gathering pipelines, underground natural gas storage facilities, and liquefied natural gas facilities. Among the proposed amendments for part 192-regulated gas pipelines are strengthened leakage survey and patrolling requirements; performance standards for advanced leak detection programs; leak grading and repair criteria with mandatory repair timelines; requirements for mitigation of emissions from blowdowns; pressure relief device design, configuration, and maintenance requirements; and clarified requirements for investigating failures. Finally, PHMSA proposes expanded reporting requirements for operators of all gas pipeline facilities within DOT's jurisdiction, including underground natural gas storage facilities and liquefied natural gas facilities.

DATES: Written comments on this NPRM must be submitted by July 17, 2023. The agency will, consistent with 49 CFR 190.323, consider late-filed comments to the extent practicable.

ADDRESSES: You may submit comments identified by the docket number PHMSA–2021–0039 by any of the following methods:

E-Gov Web: https://www.regulations.gov. This site allows the public to enter comments on any **Federal Register** notice issued by any agency. Follow the online instructions for submitting comments.

Mail: Docket Management System: U.S. Department of Transportation, 1200 New Jersey Avenue SE, West Building Ground Floor, Room W12–140, Washington, DC 20590–0001.

Hand Delivery: U.S. DOT Docket Management System, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590–0001 between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Fax: 1–202–493–2251.

Instructions: Please include the docket number PHMSA–2021–0039 at the beginning of your comments. If you submit your comments by mail, submit two copies. If you wish to receive confirmation that PHMSA has received your comments, include a self-addressed stamped postcard. Internet users may submit comments at *https://www.regulations.gov/.*

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Privacy Act: In accordance with 5 U.S.C. 553(c), DOT solicits comments from the public to better inform its rulemaking process. DOT posts these comments, without edit, including any personal information the commenter provides, to *www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), that can be reviewed at *www.dot.gov/privacy.*

Confidential Business Information: Confidential Business Information (CBI) is commercial or financial information that is both customarily and actually treated as private by its owner. Under the Freedom of Information Act (FOIA, 5 U.S.C. 552), CBI is exempt from public disclosure. If your comments responsive to this document contain commercial or financial information that is customarily treated as private, that you actually treat as private, and that is relevant or responsive to this notice, it is important that you clearly designate the submitted comments as CBI. Pursuant to 49 CFR 190.343, you may ask PHMSA to give confidential treatment to information you give to the agency by taking the following steps: (1) mark each page of the original document submission containing CBI as ''Confidential''; (2) send PHMSA, along with the original document, a second copy of the original document with the CBI deleted; and (3) explain why the information you are submitting is CBI. Submissions containing CBI should be sent to Sayler Palabrica, Office of Pipeline Safety (PHP–30), Pipeline and Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, or by email at *sayler.palabrica@dot.gov.* Any commentary PHMSA receives that is not specifically designated as CBI will be placed in the public docket.

Docket: For access to the docket to read background documents or comments received, go to *http://www.regulations.gov.* Follow the online instructions for accessing the docket. Alternatively, you may review the documents in person at the street address listed above.

FOR FURTHER INFORMATION CONTACT: Sayler Palabrica, Transportation Specialist, by telephone at 202–744–0825 or by email at *sayler.palabrica@dot.gov.*

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of Regulatory Action

This notice of proposed rulemaking (NPRM) proposes a series of regulatory amendments to the Federal pipeline safety regulations (49 CFR parts 190 through 199) in response to a bipartisan congressional mandate in the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020, Pub. L. 116–260) and in support of the Biden-Harris Administration's U.S. Methane Emissions Reduction Action Plan. The amendments would reduce both ''fugitive emissions'' (meaning unintentional emissions resulting from leaks and equipment failures) and ''vented emissions'' (meaning those emissions resulting from blowdowns, equipment design features, and other intentional releases, also called ''intentional emissions'') from over 2.7 million miles of gas transmission, distribution, and gathering pipelines and other gas pipeline facilities as well as 403 underground natural gas storage facilities (UNGSFs) and 165 liquefied natural gas (LNG) facilities, thereby improving public safety, promoting environmental justice, and addressing the climate crisis.

The Federal pipeline safety regulations currently covering leak detection and repair reflect a regulatory approach focused on public safety risks posed by incidents on gas pipeline facilities. The regulations do not sufficiently capture environmental costs, align with the importance attached to environmental protection in PHMSA's enabling statutes,[1] or reflect the scientific consensus that prompt reductions in methane emissions from natural gas infrastructure are critical to limiting the impacts of climate change. This current approach also foregoes opportunities to ensure timely identification and repair of leaks that can degrade into catastrophic failures and incidents threatening to public safety. The Federal leak detection and repair standards for gas pipelines have remained largely unchanged since the 1970s despite significant improvements in leak detection technology and operator practices and the increasingly urgent and tangible threats from climate change. The current pipeline safety regulations do not include *any* meaningful performance standards for leak detection equipment, nor requirements that leverage the significant advancements in the sensitivity, efficiency, and variety of leak detection technologies in the last five decades. Further, the current pipeline safety regulations do not explicitly require repair of all—or even most—leaks on gas pipeline facilities. Leaks that an operator determines do not to present an existing or probable public safety hazard do not need to be repaired at all regardless of the resulting environmental harms posed by that release. Current regulations also do not prescribe specific timeframes for the timely repair of hazardous or any other leaks, other than leaks associated with certain metal loss, cracking, and denting defects that are discovered on gas transmission piping during an integrity assessment in accordance with gas transmission integrity management in subpart O of 49 CFR part 192 or § 192.714. Additionally, despite a new self-executing section of the PIPES Act of 2020, described below, current regulations tolerate significant intentional emissions of methane and other gases, even in non-emergency situations, by allowing venting, blowdowns, and other large-volume releases of gas from all PHMSA-jurisdictional pipeline facilities without restriction. Consistent with the pipeline safety regulations' historical lack of emphasis on the environmental consequences of gas releases, PHMSA's minimum incident reporting threshold was established principally to better reflect the economic consequence of lost gas[2] and was set at 3 million standard cubic feet (MMCF), which leaves many large-volume gas releases unreported. And PHMSA has no reporting requirements for intentional releases of gas at all.

Congress targeted these regulatory shortcomings in the bipartisan PIPES Act of 2020. Section 113 mandated that PHMSA establish performance standards for leak detection and repair programs for certain part 192-regulated[3] gas gathering, transmission, and distribution operators reflecting commercially available advanced technology and practices for the identification, location, categorization, and repair of all leaks that are hazardous to public safety or the environment. Section 114 of the PIPES Act of 2020, moreover, requires operators of *all* pipeline facilities with maintenance and inspection procedures to update pertinent manuals to address the elimination of hazardous leaks and minimize releases of natural gas—whether fugitive emissions from leaks or intentional releases due to venting from maintenance and other activities—and repair or remediate pipelines known to leak. And section 118 of the PIPES Act of 2020 clarified that PHMSA must consider environmental benefits equally with public safety benefits. The mandates in the PIPES Act of 2020 align with the importance of addressing climate change by reducing methane emissions.

PHMSA proposes a number of regulatory revisions to minimize emissions of methane and other (flammable, toxic, or corrosive) gases from, and improve public safety of, new and existing offshore gas gathering, regulated onshore gas gathering, transmission and distribution pipelines, UNGSFs and LNG facilities. PHMSA expects that the proposed regulatory amendments would yield prompt and meaningful reduction of methane emissions, a key contributor to climate change; improve public safety; and mitigate the disproportionate burden of those environmental and safety risks historically placed on minority, low-income, or other underserved and disadvantaged populations and communities.

B. Summary of the Regulatory Provisions

This NPRM contains the following proposed changes to the regulations: (1) strengthen leakage survey and patrolling requirements at §§ 192.9, 192.705, 192.706, 192.723 for all part 192-regulated gas pipelines, as well as introduce periodic methane leakage survey requirements for part 193-regulated LNG facilities; (2) introduce for all part 192-regulated gas pipelines an Advanced Leak Detection Program (ALDP) performance standard at a new § 192.763 reflecting the capabilities of

[1] 49 U.S.C. 60102(b)(1)(B)(ii), 60102(b)(2)(A)(iii), 60102(b)(5), 60102(q)(1)(B), 60102(q)(2)(B)(i).

[2] Prior to the adoption of the volumetric incident criterion, the cost of lost gas was included in the property damage calculation. In the NPRM that proposed the adoption of a volumetric threshold, PHMSA described both a petition from the Interstate Natural Gas Association of America noting that more incidents were reportable due to changes in the cost of gas, as well as a GAO recommendation (GAO–06–946) to adjust the incident reporting criteria to account for the cost of lost gas. That NPRM did not identify environmental considerations among the motivations for that change in incident reporting requirements. *See* 74 FR 31675, 31677 (July 2, 2009).

[3] Throughout this NPRM, PHMSA uses the phrase ''part 192-regulated gas gathering pipelines'' to refer to offshore gas gathering pipelines, as well as Types A, B, and C ''regulated onshore gas gathering'' pipelines—all of which are subject to certain part 192 requirements under §§ 192.8 and 192.9. Such ''part 192-regulated gas gathering pipelines'' does not include ''reporting-regulated'' or ''Type R'' gas gathering pipelines as defined in §§ 191.3 and 192.8(c)(3), which are not subject to part 192 safety requirements. Similarly, PHMSA also refers to ''part 192-regulated gas pipelines'' to collectively refer to gas transmission, distribution, offshore gathering, and Types A, B, and C onshore gathering pipelines subject to part 192 requirements. ''Gas pipeline facilities'' is defined as ''a pipeline, a right of way, a facility, a building, or equipment used in transporting gas or treating gas during its transportation''—this broader definition applies to all part 192-regulated gas pipelines, UNGSFs, and part 193-regulated LNG facilities. *See* 49 U.S.C. 60101(a)(3).

commercially available advanced technologies and practices; (3) amend § 192.703 to require operators of all part 192-regulated gas pipelines to grade and repair all leaks, and not merely those that pose public safety risks; (4) establish for all part 192-regulated gas pipelines minimum criteria for leak grades and associated repair schedules prioritized by safety and environmental hazard at a new § 192.760; (5) require reductions in intentional sources of methane emissions by minimizing releases associated with blowdowns and other vented emissions from gas transmission, offshore gas gathering, and Type A gas gathering pipelines (at § 192.770) and LNG facilities (at § 193.2523); (6) require operators of certain part 192-regulated gas pipelines to reduce emissions associated with the design, configuration, and maintenance of pressure relief devices (§§ 192.199 and 192.773); (7) codify in Federal regulations a congressional requirement for operators of gas pipeline facilities to implement written procedures to eliminate hazardous leaks, minimize releases of natural gas, and remediate or replace pipelines known to leak (§§ 192.9, 192.12, 192.605, 193.2503, and 193.2605); (8) expand reporting requirements (at §§ 191.3 and 191.19) and recordkeeping requirements (at §§ 192.760 and 192.773) to provide higher-quality information on unintentional and intentional gas releases from gas pipeline facilities; (9) require that Types A, B, and C gathering pipeline operators submit geospatial pipeline location data to the National Pipeline Mapping System (NPMS) pursuant to § 191.29; (10) incorporate explicit reference to *environmental* harm among the ''hazards'' addressed in certain parts 191 and 192 requirements; and (11) introduce, for certain components and equipment within part 193-regulated LNG facilities, at a new § 193.2624, requirements for periodic methane leakage surveys using leak detection equipment and repair of identified leaks pursuant to operators' written maintenance or abnormal operations procedures. PHMSA proposes an effective date for this rulemaking of 6 months following publication of a final rule in the **Federal Register**. The eleven proposed requirements are described in the paragraphs immediately below, and further detail is provided in sections IV and V.

First, PHMSA proposes increased leakage survey frequencies for distribution pipelines outside of business districts,[4] annual leakage surveys for distribution pipelines that lack cathodic protection or which are known to leak based on their material (cast-iron, cathodically unprotected steel, wrought-iron, and certain plastic pipelines), design, or operational and maintenance history; and for gas transmission, offshore gathering, and Types A, B, and C gathering pipelines in high consequence areas (HCAs), with the most frequent leakage surveys to be performed on gas transmission and Types A and B gathering pipelines located in HCAs within Class 4 locations. PHMSA also proposes to increase minimum patrolling frequencies for gas transmission, offshore gathering, and Type A gathering pipelines and to introduce requirements for annual patrolling of Type B and Type C gathering pipelines. Finally, PHMSA proposes to establish methane leakage survey requirements for LNG facilities other than tanks.

Second, PHMSA proposes to introduce an ALDP performance standard that would require operators of part 192-regulated gas pipelines to demonstrate, by conducting engineering tests and analyses, that their suite of leak detection equipment, procedures, and analytics are capable of detecting all leaks above a minimum concentration threshold when measured in close proximity to the pipeline. PHMSA proposes to require that leakage surveys be performed using commercially available advanced technology and practices consistent with the proposed ALDP performance standard. PHMSA also proposes to require a minimum sensitivity for leak detection equipment used in leakage surveys and leak investigations. PHMSA proposes to limit the use of human or animal senses for leakage surveys to offshore, submerged gas transmission and gathering pipelines. Human senses may also be used for gas transmission and regulated gas gathering lines in Class 1 and Class 2 locations outside of HCAs, but only with prior notification to and no objection from PHMSA in accordance with § 192.18.

Third, PHMSA proposes to require operators of gas transmission, distribution, and part 192-regulated gathering pipelines to identify, locate, classify, and repair in a timely manner *all* leaks. Part 192 provisions governing the repair of leaks are narrowly focused on public safety risks associated with ignition of large-volume, instantaneous releases and accumulated gas; they are unclear regarding when, if at all, most leaks must be repaired. Although some—not all—part 192-regulated pipelines are subject to a general maintenance requirement in § 192.703(c) to ''promptly repair hazardous leaks,'' part 192 maintenance requirements neither define ''hazardous leak'' in terms of risks to the environment nor establish meaningful timelines for repair of hazardous or any other leaks. These proposed amendments would address the section 113 mandate of the PIPES Act of 2020 requiring identification, location, classification, and repair of leaks hazardous to either public safety or the environment.

Fourth, this NPRM proposes that operators of gas transmission, distribution, and part 192-regulated gathering pipelines must classify and repair all identified leaks on a schedule that depends on the severity of public safety and environmental risks. PHMSA's proposed requirements build on the tiered framework of the Gas Piping Technology Committee (GPTC) ''Guide for Gas Transmission and Distribution Piping Systems''[5] leak grading and repair criteria. PHMSA's proposed framework would require the classification of every leak (as either grade 1, grade 2, or grade 3) and to prioritize remediation of leaks posing the most significant risks to public safety or the environment.

Fifth, PHMSA proposes requirements for the mitigation of intentional emissions such as blowdowns on gas transmission, offshore gas gathering, and Type A gas gathering pipelines and LNG facilities. This proposal requires an operator to choose from among prescribed, proven, cost-effective mitigation measures when performing blowdowns related to operations, maintenance, or construction.

Sixth, PHMSA proposes requirements for operators of gas transmission, distribution, offshore gathering, and Types A, B, and C gathering pipelines to design and configure all new and modified pressure relief and limiting devices to minimize unnecessary releases and to assess and remediate any relief devices that operate outside of the tolerances established in the operator's procedures. These proposed

[4] The term ''business district'' is not defined in part 192. However, in a letter of interpretation PHMSA stated that the term normally refers to an area ''associated with the assembly of people in shops, offices and the like,'' marked by the conduct of ''buying and selling commodities and services, and related transactions.'' *See* PHMSA, Interpretation Response Letter No. PI–72–038 (Aug. 16, 1972).

[5] Gas Piping Technology Committee Z380, ANSI GPTC Z380.1–2022, ''The Guide for Gas Transmission, Distribution, and Gathering Piping Systems'' Including Addenda 1 and 2 (2022).

requirements would minimize unintended and unnecessary releases of gas to the atmosphere, better protecting against environmental and public safety hazards posed by malfunctioning or poorly designed and configured pressure relief devices.

Seventh, PHMSA proposes to codify in regulation self-executing requirements from section 114 of the PIPES Act of 2020, which obliges operators of gas pipeline facilities to have written procedures that address the elimination of hazardous leaks, minimize releases of natural gas, and provide for repair or replacement of pipelines known to leak based on material, design, or past operating and maintenance histories. These changes would support PHMSA's cooperation with states undertaking inspection and enforcement activity in connection with those requirements.

Eighth, this NPRM proposes a series of changes to part 191 reporting requirements. PHMSA proposes to introduce requirements for reporting large-volume releases of gas from all gas pipeline facilities, including intentional releases, that are not currently captured by the definition of an incident in part 191. Specifically, this NPRM proposes to create a report for both unintentional releases and, for the first time, intentional releases of 1 MMCF or more of gas from any gas pipeline facility. PHMSA also proposes revisions to annual reporting requirements for gas transmission, distribution, offshore gathering, and Types A, B, and C gathering pipelines to convey information regarding the number and grade of all leaks detected and repaired each calendar year as well as estimated emissions from those leaks.

Ninth, this NPRM further proposes to extend NPMS reporting requirements at § 191.29 to offshore gas gathering pipelines as well as Types A, B, and C onshore gas gathering pipelines.

Tenth, this NPRM proposes incorporation of explicit reference to *environmental* harm among the ''hazards'' addressed in certain part 191 and 192 requirements, consistent with section 118 of the PIPES Act of 2020. PHMSA's proposed expansion of the concept of ''hazards'' to encompass environmental harms would not extend to integrity management (IM) regulations in part 192, subparts O (gas distribution pipelines) and P (gas transmission pipelines), which would remain focused on safety, and certain other existing requirements directed at hazards to public safety in particular (described in detail in section IV.J).

Finally, this NPRM proposes a new § 193.2624 that would oblige operators of part 193-regulated LNG facilities to perform quarterly methane leakage surveys of non-tank equipment and components within an LNG facility using leak detection equipment satisfying the minimum 5 parts per million (ppm) sensitivity proposed elsewhere within this NPRM. Operators would also need to repair any leaks identified in a manner and on a schedule consistent with their maintenance or abnormal operations procedures. PHMSA also proposes conforming changes to annual report forms for LNG facilities to ensure meaningful reporting of methane leaks discovered and repaired pursuant to the proposed § 193.2624.

C. Costs and Benefits

Consistent with Executive Order (E.O.) 12866 and the requirements of the Federal Pipeline Safety Laws,[6] PHMSA has prepared an assessment of the benefits and costs (to include pertinent commercial benefits, public safety benefits, environmental benefits, equity benefits, compliance costs, and other risks) of this proposed rule, as well as reasonable alternatives. PHMSA estimates that emission reductions under the proposed rule correspond to approximately 72 percent of unintentional emissions from regulated gathering pipelines, 17 percent of unintentional emissions from transmission pipelines, and 44 to 62 percent of unintentional emissions from distribution pipelines. These shares are relative to modeled baseline emissions projected over the period of analysis based on the pipeline mileage, empirical emission factors, and existing survey and repair practices. Further, PHMSA estimates that the total avoided blowdown emissions under the proposed rule correspond to approximately 43 percent of baseline blowdown emissions. PHMSA estimates that the proposed rule would result in monetized net benefits between $341 to $1,440 million per year using a 3 percent discount rate. PHMSA also anticipates additional unquantified benefits to public safety and the environment, each discussed throughout this NPRM and its supporting documents (including the Preliminary Regulatory Impact Analysis (RIA) and draft Environmental Assessment (EA), each available in the docket for this NPRM).

The regulatory amendments proposed in this NPRM are expected to improve public safety, reduce threats to the environment (including, but not limited to, reduction of methane emissions contributing to the climate crisis), and promote environmental justice for minority populations, low-income populations, and other underserved and disadvantaged communities. Additionally, reducing product losses results in cost savings for natural gas shippers and consumers and improves the efficiency and reliability of U.S. energy infrastructure. PHMSA expects that each of the elements of this rulemaking as proposed in this NPRM would be technically feasible, reasonable, cost-effective, and practicable because of the public safety, environmental, and equity benefits of the proposed regulatory amendments described in this NPRM and its supporting documents (including the Preliminary RIA and draft EA) which justify any associated costs. PHMSA has preliminarily determined that the proposed rule is superior to alternatives considered in the Preliminary RIA.

II. Background

A. The Urgency of Methane Emissions Reductions in Confronting the Climate Crisis

The primary component of natural gas is methane (CH_4). Methane is a greenhouse gas, or GHG, which means that its concentration in the atmosphere affects the climate and temperature of the Earth by trapping heat in the atmosphere. Methane is released from both natural and anthropogenic sources, the latter of which includes leaks and other releases from natural gas pipeline systems. Methane is the second most abundant anthropogenic GHG in the Earth's atmosphere, after carbon dioxide (CO_2), by concentration and accounts for the second-greatest contribution to total radiative forcing (warming effect).[7] The Environmental Protection Agency (EPA) calculated that methane made up approximately 11 percent (by mass of CO_2 equivalents) of the annual GHG emissions in 2019 within the United States, whereas carbon dioxide made up 79 percent of the total GHG emissions over the same period.[8] According to the 2021 installment of the Sixth Assessment Report (2021 IPCC Report) from Working Group I of the Intergovernmental Panel on Climate Change (IPCC), the atmospheric concentration of methane gas was

[6] 49 U.S.C. 60101 *et seq.* (Federal Pipeline Safety Laws). The specific provision referenced in the above discussion is 49 U.S.C. 60102(b)(5).

[7] National Oceanic and Atmospheric Administration (NOAA), ''Annual Greenhouse Gas Index'' at Figure 3 & Table 2 (Spring 2022), *https://gml.noaa.gov/aggi/aggi.html.*

[8] EPA, ''Overview of Greenhouse Gases,'' *https://www.epa.gov/ghgemissions/overview-greenhouse-gases#methane* (last accessed December 5, 2022).

measured at 1,866 parts per billion (ppb), compared with 410 ppm of carbon dioxide.[9]

However, this comparatively small concentration of methane in the atmosphere makes an outsized contribution to climate change. The 2021 IPCC Report notes that anthropogenic methane emissions account for approximately one-third of warming of global average surface temperatures attributed to well-mixed GHG [10] emissions since 1850.[11] The IPCC also noted that in 2019, atmospheric CH_4 concentrations were higher than at any time in 800,000 years, and that ''strong, rapid and sustained reductions in CH_4 emissions'' would be needed to offset short-term warming effects.[12]

Once emitted into the atmosphere, some GHGs can persist in the atmosphere for a long time. Carbon dioxide, for instance, remains in the atmosphere for 300 to 1000 years.[13] Methane, on the other hand, is more short-lived than CO_2 but is much more potent in trapping heat in the atmosphere. Methane only lasts in the atmosphere for approximately 12 years once released; however, it traps approximately 25 times more energy than an equal mass of carbon dioxide over a 100-year period.[14] Because methane is a more potent, but more short-lived, GHG compared to carbon dioxide, reducing methane emissions would have a more rapid and significant effect on reducing heat-trapping potential of the atmosphere than an equivalent reduction in carbon dioxide and would therefore result in a greater effect on climate change mitigation in the short term.[15]

Authoritative scientific projections underscore the need for achieving a prompt reduction in methane emissions. The 2021 IPCC Report concluded that urgent action to reduce emissions across all GHG categories is necessary to minimize global warming and avoid the most destructive effects of climate change.[16] The report details five possible future emissions and warming scenarios: two high emissions scenarios (SSP3–7.0 and SSP5–8.5), an intermediate scenario with emissions similar to the status quo through mid-century (SSP2–4.5), and two relatively low-emissions scenarios (SSP1–1.9 and SSP1–2.6). Of these, only the two low-emissions scenarios are likely to hold temperature increases below the Paris Agreement's target of limiting the increase in global average surface temperature to 2.0 °C above 1850 levels by the end of the century,[17] and only the very low-emissions scenario (SSP1–1.9) is likely to limit warming to 1.5 °C by the end of the century (specifically, between 1.0 ° to 1.8 °C above 1850 levels, consistent with the Paris Agreement). Both of those low-emissions scenarios require cutting methane emissions by approximately half of 2015 levels before 2050.[18] Rapid and full-scale efforts to reduce methane and other GHG emissions are needed to achieve the very low-emissions scenario (SSP1–1.9).[19] In contrast, the intermediate scenario (SSP2–4.5) results in potentially dangerous warming of 2.0 °C by midcentury, rising to between 2.1 ° to 3.5 °C by 2100.

B. Dimensions of the Climate Crisis

Near-term methane emissions reductions are especially compelling because global climate change is already causing observable, damaging effects on the environment. The 2021 IPCC Report shows that the environmental and social consequences of climate change are no longer abstract, distant problems: scientists note increased surface temperature, extreme weather events, rising sea levels, and other consequences are being felt today and predict those effects will intensify in the coming decades without immediate action to control GHG emissions to avoid or stave off the worst effects of climate change. Higher average surface temperatures will result in sea level rise, severe heat waves, and more intense extreme weather events (hurricanes, storms, droughts, and floods), in turn altering water supplies, damaging habitats, and promoting wildfires. According to the findings from the 3rd and 4th National Climate Assessment Reports released by the U.S. Global Change Research Program,[20] these dimensions of climate change will have severe consequences for the human population throughout the United States including alteration of population distributions; widespread property damage; compromised local economies; disrupted agriculture, fisheries, and other ecosystems; and degraded public health.

The most immediate impact of climate change worldwide has been, and will continue to be, an increase in average surface temperatures. The average global surface temperature during 2021 was 1.51 degrees Fahrenheit (0.84 degrees Celsius) warmer than the average temperature in the 20th century (57.0 degrees Fahrenheit) and was 1.87 degrees Fahrenheit (1.04 degrees Celsius) warmer than the average temperature between 1880–1900, which NOAA describes as a ''reasonable surrogate for pre-industrial conditions.'' [21] That observed surface temperature increase has resulted in cascading consequences for the natural world already; as more GHGs are added to the atmosphere, the rate of warming is expected to continue to accelerate.

Increasing the average surface temperature of the Earth changes the frequency and intensity of extreme temperature events. Higher average surface temperatures means that heat waves everywhere will become more frequent and more intense.[22] The IPCC estimates that current levels of warming

[9] IPCC, *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change, Summary for Policymakers* (SPM)–5 (2021). In the 2021 IPCC Report, atmospheric concentration of CH_4 since 1984 (1980 for CO_2) is based on merging observed gas concentration in the lower troposphere from the NOAA Global Monitoring Laboratory and the Advanced Global Atmospheric Gases Experiment monitoring networks. Emissions in 1850 and earlier are estimated based on assessments of multiple ice cores. 2021 IPCC Report, Table 2.2 and Table AIII.1a.

[10] According to the IPCC, well-mixed GHGs include CO_2, N_2O, and CH_4. 2021 IPCC Report, 2.2. These gases ''generally have lifetimes of more than several years'' and therefore are relatively uniformly distributed within the troposphere (lower-atmosphere). 2021 IPCC Report, 2.2.3.

[11] 2021 IPCC Report, SPM–8.

[12] 2021 IPCC Report, SPM–9, SPM–36.

[13] Buis, ''The Atmosphere: Getting a Handle on Carbon Dioxide'' (Oct. 9, 2019).

[14] EPA, ''Overview of Greenhouse Gases,'' *https://www.epa.gov/ghgemissions/overview-greenhouse-gases* (last accessed July 20, 2022).

[15] EPA, ''Importance of Methane,'' *https://www.epa.gov/gmi/importance-methane* (last accessed July 20, 2022).

[16] PHMSA acknowledges much of the discussion in section II and elsewhere in this NPRM is focused on methane emissions from natural gas pipeline facilities, as those facilities constitute the great majority of gas pipeline facilities subject to parts 191 and 192. However, PHMSA parts 191 and 192 requirements are not limited to natural gas pipelines; rather, they also apply to pipeline facilities transporting other gases which are flammable, toxic, or corrosive—releases of which may entail significant public safety or environmental consequences (including potential contributions to climate change) in their own right. *See* §§ 191.3 and 192.3 (definitions of ''gas'' for the purposes of parts 191 and 192, respectively).

[17] 2021 IPCC Report, 1.2.

[18] 2021 IPCC Report, SPM–16, Table SPM.1.

[19] 2021 IPCC Report, Table SPM.1.

[20] *See* U.S. Global Change Research Program, *Climate Science Special Report: Fourth National Climate Assessment, Volume I* (2017); U.S. Global Change Research Program, *Climate Change Impacts in the United States: The Third National Climate Assessment* (2014).

[21] *See* NOAA National Centers for Environmental Information, *Monthly Global Climate Report for Annual 2021* (Jan. 2022), *https://www.ncei.noaa.gov/news/global-climate-202112.*

[22] 2021 IPCC Report, SPM–8, SPM–18.

have made 10-year extreme heat events [23] approximately 1.2 degrees Fahrenheit more intense and 2.8 times more frequent. Likewise, the IPCC estimates that 50-year extreme heat events have become 4.8 times more frequent. The estimated frequency and intensity of extreme heat events will increase further with additional warming, especially in warmer summer months.[24]

A well-known consequence of elevated (average and instantaneous) surface temperatures is rising sea levels. The global sea level has risen by about 5.9–9.8 inches (0.15–0.25 meters) between 1901 and 2018 and the rate of increase and degree to which sea level rise can be attributed with confidence to anthropogenic climate change have both increased since 1971.[25] The IPCC has determined that it is ''virtually certain'' that the global sea level will rise further by 2100, as land ice continues to melt and seawater expands as it warms, with greater sea level rise resulting from higher GHG emissions scenarios.[26] An expected contributor to global sea level rise is the loss of virtually all summer ice from the Arctic Ocean before 2050.[27] Global average sea levels are projected to rise an additional 1.0–4.3 feet by 2100 under intermediate emissions scenarios, with a global sea level rise in excess of 8 feet possible by 2100 under higher emissions scenarios.[28]

Rising average surface temperatures also alter water cycles and weather patterns such as precipitation and hurricanes. As noted above, higher average and instantaneous surface temperatures will result in loss of soil moisture in most regions. Meanwhile, some areas are increasingly likely to experience heavy downpours, while other areas will likely receive far less precipitation than in years past.[29] Areas that are projected to have less total precipitation and higher temperatures will likely become more susceptible to drought and wildfires as a result; as described below, the United States has already seen the acreage affected by wildfires trend upwards in recent decades. Scientists also project that the recent trend toward more frequent heavy precipitation events will continue, even in areas where the total precipitation is expected to decrease, which could lead to increased flooding risks, erosion, and land subsidence. As further noted below, earth and water movement are also threats to pipeline integrity that can lead to pipeline incidents and accidents that threaten public safety and the environment.[30] Similarly, scientists have observed that it is likely that hurricanes have become stronger and more intense and determined that it is likely that anthropogenic climate change has increased rainfall rates associated with hurricanes and other tropical cyclones.[31]

The United States has a front-row seat to the effects of climate change. Already, many areas of the United States are seeing increases in the duration and frequency of heat waves and altered precipitation patterns. The 2021 IPCC Report describes observed increases in extreme heat and drought events occurring around the world, including western North America.[32] The Colorado River in the Southwest United States is facing its first-ever water shortage, a phenomenon that is directly linked to warming temperatures. Due to this historic shortage, in 2022, the U.S. Department of the Interior's Bureau of Reclamation proposed significant cuts to water allocations from the Colorado River to Arizona, Nevada, and Mexico in order to ensure continued operation of hydroelectric generation facilities.[33] In late June and early July of 2021, the Western part of the United States and Canada suffered a heat wave that was likely exacerbated by climate change, with consequences ranging as far north as the Yukon territory in Canada, and as far inland as the State of Montana. Much of the Pacific Northwest reached temperatures that were 20 to 35 degrees Fahrenheit above normal during this heat wave, with several daily high temperature records being broken. Temperatures grew so hot that nighttime low temperatures in many areas were higher than historical average daytime high temperatures.

Higher average surface temperatures and extreme instantaneous temperatures have also exacerbated wildfires in the United States. Prolonged heat has led to dry vegetation, and the heat and dry vegetation have contributed to the severity of several wildfires. According to the research compiled in the 4th National Climate Assessment, drought in California and the Colorado River Basin have made forests ''more susceptible to burning'' and caused ''spring-like temperatures to occur earlier in the year,'' extending the western fire season [34] and doubling the cumulative forest area burned by wildfires between 1984 and 2015.[35] Wildfires pose serious health risks, including illnesses from smoke inhalation and contaminated drinking water, and cause significant property damage ($3.1 billion in the Los Angeles area alone from 1990 to 2009, or approximately $4 billion in 2021 dollars).[36] The 4th National Climate Assessment cautions that the frequency and intensity of wildfires in the Western United States will increase with further warming, with higher emissions scenarios estimating a 25% increase in wildfires in the Southwest region and three times as many wildfires that exceed 5,000 hectares in size.[37] Researchers at the University of California, Los Angeles and Columbia University have determined that the 22-year period from 2000–2021 was the driest such period in the Southwestern United States since the year 800, due in large part to climate change.[38] Climate change poses a significant threat of extending the drought even further. In fact, the Southwestern drought is expected to persist through at least the end of 2022 and become the longest megadrought on record in the Southwestern United States, further endangering sources of water, and the

[23] Defined by the IPCC as ''daily maximum temperatures over land that were exceeded on average once in a decade (10-year event) or once every 50 years (50-year event) during the 1850–1900 reference period.'' *See* 2021 IPCC Report, SPM–24.

[24] 2021 IPCC Report, SPM–23.

[25] 2021 IPCC Report, SPM–6.

[26] 2021 IPCC Report, SPM–28.

[27] European Space Agency (ESA), ''Simulations Suggest Ice-Free Arctic Summers by 2050'' (May 13, 2020), *https://climate.esa.int/en/projects/sea-ice/news-and-events/news/simulations-suggest-ice-free-arctic-summers-2050/.*

[28] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Southeast* at 758. (2018).

[29] 2021 IPCC Report, SPM–15.

[30] PHMSA, ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards,'' 87 FR 33576 (June 2, 2019) (Advisory Bulletin ADB–2022–01).

[31] 2021 IPCC Report, SPM–9.

[32] 2021 IPCC Report, SPM–12.

[33] Yanchin, ''Interior Threatens Colorado River Cuts,'' *E&E News* (Oct. 28, 2022), *https://www.eenews.net/articles/interior-threatens-colorado-river-cuts/.*

[34] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Southwest* at 1115, 1116 (2018).

[35] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Southwest* at 1115, 1135 & Figure 25.4 (2018).

[36] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Southwest* at 1116 (2018); Inflation adjustment via Consumer Price Index inflation from December 2009 to December 2021.

[37] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Southwest* at 1116 (2018).

[38] Williams et al., ''Rapid Intensification of the Emerging Southwestern North American Megadrought in 2020–2021,'' 12 *Nature Climate Change* (Mar. 1, 2022).

communities that rely on them, throughout the region.[39]

The United States will also experience dramatically altered precipitation and weather patterns from climate change. Increases in GHG concentrations in the atmosphere have already led to increased Atlantic hurricane activity, and a warming climate is projected to cause extreme rainfall and significant regional flooding from hurricanes, nor'easters, and other severe storms, in addition to exacerbating the intensity of hurricanes in the Atlantic and eastern North Pacific.[40] While projections are difficult to make for infrequent, smaller weather events like tornadoes and severe thunderstorms, these events have also been recently exhibiting changes that may be caused by climate change.[41] Moreover, tornadoes can be generated by hurricanes (such as the 25 tornadoes produced by Hurricane Irma in 2017, mostly along the east coast of Florida), and more intense hurricanes could generate more tornadoes.

Climate change-induced sea level rise is and will continue to be experienced in the United States. Sea level rise has already led to more frequent high tide flooding. One study of flooding in 27 communities cited in the Fourth National Climate Assessment found that the frequency of high tide flooding in several communities has increased by a factor of 5 or more, and that such flooding increased by a factor of 10 or more in Atlantic City (NJ), Baltimore (MD), Annapolis (MD), Wilmington (DE), Port Isabel (TX), and Honolulu (HI).[42] In the Southeast, tidal data from the National Oceanic and Atmospheric Administration shows sea level rise of 1–3 feet has already occurred over the past 100 years. The effects of sea level rise are not distributed equally across the world, nor along the U.S. coastline; instead, the Northeast United States, eastern coast of Florida, and western Gulf Coast regions will likely experience the worst impacts from rising sea levels and coastal flooding due to ocean circulation, land subsidence, and uneven ice melt. The 4th National Climate Assessment identifies an average of 2 to 4.5 feet as the most probable sea level rise in the Northeast United States before 2100 with worst-case estimates projecting sea level rise of more than 11 feet over the same period.[43] Under higher emission projections, the 4th National Climate Assessment found it likely that all U.S. coastlines, other than Alaska, will experience sea level rise greater than the global averages due to Antarctic ice loss. By 2100, sea level rise is likely to submerge real estate worth between $238–507 billion across the United States and force the migration of substantial elements of the U.S. population.[44] Average sea level rise of 6 feet by 2100 could displace an estimated 13.1 million people along the U.S. coasts.[45]

These and other dimensions of the climate crisis also have disastrous near and long-term consequences for human health. The EPA Administrator, as early as 2009[46] (and again in 2016),[47] determined that methane along with 5 other ''well-mixed greenhouse gases'' together constituted a harmful air pollutant that endangered public health and welfare of persons. According to the 2016 assessment of human health impacts of climate change from the U.S. Global Change Research Program (2016 Assessment), climate change will likely contribute to ''thousands to tens of thousands of premature heat-related deaths in the summer'' in the United States in the years ahead.[48] Indeed, the heat wave in summer 2021 discussed above resulted in excess heat-related deaths of 143 in Washington, 119 in Oregon, 13 in California, and 619 in British Columbia according to public health authorities.[49] The 2016 Assessment also notes climate change is likely to result in ''meteorological conditions increasingly conducive to forming ozone over most of the United States,'' which is likely to result in ''premature deaths, hospital visits, lost school days, and acute respiratory symptoms.''[50] The 4th National Climate Assessment also notes that, in addition to the immediate hazard to life and property, climate change-induced wildfires will result in direct hazards to human health in the form of burns, smoke inhalation, exacerbation of particulate and ozone pollution, and negative impacts on water quality.[51]

Increased intensity and frequency of extreme weather events (such as hurricanes and floods) from climate change also threaten human life and property. In the Northeast, high-tide flooding will impact low-lying areas with increased frequencies and could result in an additional $6—9 billion in damages per year by 2100 in high emissions scenarios.[52] In 2017, Hurricane Irma caused, in the United States, the deaths of 84 people and costs of approximately $50 billion (with Florida suffering most of these costs). In the Midwest, the Fourth National Climate Assessment found precipitation has increased by between 5% to 15% since the 1901–1960 period; the Fourth National Climate Assessment projects that seasonal precipitation during winter and spring associated with flood risk could increase by ''by up to 33% by the end of the century.''[53] Extreme precipitation events and river flooding could damage private property and transportation infrastructure and overwhelm stormwater treatment facilities, resulting in water quality impacts, especially in communities with combined sewer overflows. In the Southern Great Plains States, increased frequency and severity of severe floods was also projected for the southern

[39] Williams et al., ''Rapid Intensification of the Emerging Southwestern North American Megadrought in 2020–2021,'' 12 *Nature Climate Change* (Mar. 1, 2022).

[40] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Our Changing Climate* at 74, 95 (2018) (noting the heaviest rainfall amounts from recent storms have been estimated to be 6–7% greater than the most intense storms of the early 1900s).

[41] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Our Changing Climate* at 97 (2018).

[42] Sweet & Park, ''From the Extreme to the Mean: Acceleration and Tipping Points of Coastal Inundation from Sea Level Rise, *Earth's Future 2* at 579–600 (2014).

[43] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Northeast* at 692 (2018).

[44] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Coastal Effects* at 330, 335 (2018).

[45] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Coastal Effects* at 335 (2018).

[46] 74 FR 66495 (Dec. 15, 2009).

[47] 81 FR 54422 (Aug. 15, 2016).

[48] U.S. Global Change Research Program, *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment—Executive Summary* at 6 (2016).

[49] U.S. Department of Health and Human Services, Office of Climate Change and Health Equity, *Climate and Health Outlook: Extreme Heat* (June 2022), *https://www.hhs.gov/sites/default/files/climate-health-outlook-june-2022.pdf;* British Columbia, ''Minister's Statement on 619 Lives Lost During 2021 Heat Dome'' (June 7, 2022). *https://news.gov.bc.ca/26965*.

[50] Methane also directly contributes to adverse air quality because it is a chemical precursor to ozone.

[51] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Water* at 154 (2018); U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Air Quality* at 514, 519 (2018); U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume I—Southeast* at 755 (2018).

[52] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Northeast* at 695 (2018).

[53] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Midwest* at 914–16 (2018).

Great Plains states, potentially resulting in significant costs from flood damage and adaptation costs.[54] The Fourth National Climate Assessment also found climate change-induced degradation of natural habitats, agricultural resources, water resources, and other ecological resources threaten the viability of subsistence and commercial activities that Federally recognized Indian Tribes depend on, such as ''agriculture, hunting and gathering, fisheries, forestry, energy, recreation, and tourism,'' and threaten Tribal water allocations in the Western United States.[55]

Increased severe whether phenomena caused by climate change further threaten human health by wreaking havoc on public services and infrastructure. Hurricane Nicholas in the Gulf of Mexico in September 2021 caused widespread flooding and weeks of blackouts on the U.S. Gulf Coast, much as the increasingly long wildfire season in California is now routinely accompanied by threats of rolling blackouts. The summer 2021 heat wave that blanketed the Western United States damaged transportation infrastructure, closing multiple lanes on Interstate 5 and causing trains to operate at reduced speeds as a precaution against the potential deformation of rail tracks. Earlier, the 2017 Atlantic hurricane season produced the second and third costliest hurricanes in U.S. history, hurricane Harvey and Hurricane Maria. Hurricane Harvey caused more than 60 inches of rainfall over the Texas Gulf Coast, including the Houston metro area, and resulted in at least 68 direct casualties and approximately $125 billion in storm-related damage.[56] Hurricane Maria caused widespread devastation in Puerto Rico, resulting in approximately $90 billion dollars in damage and the near total loss of electric, water, and telecommunication infrastructure across the island, and electrical outages persisted for months across much of the island.[57]

Pipeline infrastructure is similarly vulnerable to the impacts of climate change. For example, well-documented threats to pipeline infrastructure from natural force damage (which includes incidents caused by acts of nature such as flooding, land movement, and lightning) are likely to be exacerbated by climate change. On April 11, 2019, PHMSA published an advisory bulletin on the threat that severe flooding can have on pipeline integrity, especially at water crossings.[58] As described in further detail in the advisory bulletin, flooding and related earth movements can cause damage to pipelines in and around water crossings from direct water force, impacts from debris, added strain on pipeline structures through changes in loading conditions, and other means. Flooding can also threaten pipeline integrity by causing damage to aboveground, safety-critical components such as valves, pressure regulators, relief devices, and pressure sensors. A weather-induced failure of a gas pipeline can result in releases that threaten public safety and further contribute to climate change. On May 2, 2019, PHMSA issued another advisory bulletin to remind operators of the risks to pipeline facilities from large earth movement, including subsidence and erosion events that can be intensified due to climate change.[59] PHMSA issued an update to this advisory bulletin on June 2, 2022, noting recent incidents and accidents underscoring the risks described in Advisory Bulletin ADB–2019–02.[60] This most recent bulletin notes that changing weather patterns due to climate change can weaken soil stability, increasing the likelihood of earth movement damage to pipeline facilities.

PHMSA has also documented serious pipeline integrity threats from hurricanes in an advisory bulletin published on September 1, 2011, titled ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes.'' [61] This advisory bulletin notes that hurricanes can directly damage pipelines, cause submerged pipelines to become exposed, or otherwise cause pipeline facilities to become a hazard to navigation. The advisory bulletin also noted that in 2005, Hurricane Katrina and Hurricane Rita caused extensive damage to onshore and offshore oil and gas production and transportation infrastructure in the Gulf of Mexico, which took substantial time and resources to contain and remediate. PHMSA expects more severe and frequent hurricanes will amplify the risk of damage to pipeline facilities, to the detriment of coastal communities, environments, and the reliability of the U.S. oil and gas industry.

Finally, these and other consequences of climate change have been, and are expected to continue to be, disproportionately borne by vulnerable populations in the United States—in particular by minority and low-income populations, outdoor laborers, children, and the elderly.[62] Some communities of color may be uniquely vulnerable to climate change health impacts in the United States because they live in areas where the impacts of climate change (*e.g.,* extreme temperatures and flooding) are likely to be the most significant, and because these communities tend to have limited adaptive opportunities due to a greater dependence on climate-sensitive resources (such as local water and food supplies), economic opportunities (*e.g.,* seasonal labor), and limited access to social and information resources. The 2016 scientific assessment on the *Impacts of Climate Change on Human Health* similarly found that social determinants of health (*e.g.,* access to healthcare, economic stability) are highly likely to contribute to climate change-related health impacts.[63] And insofar as gas transmission and gas gathering pipeline infrastructure is often located in the vicinity of socially vulnerable populations,[64] those populations would face the greatest risks in the event of a release from a gas pipeline damaged by climate change-induced extreme weather events.

C. Methane Emissions From Gas Pipeline Facilities

Most gas produced or consumed in the United States is transported by a gas

[54] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Southern Great Plains* at 1003–06 (2018).

[55] U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Tribes and Indigenous Peoples* at 579 (2018).

[56] Eric S. Blake and David A. Zelinsky. NOAA National Hurricane Center. 'National Hurricane Center Tropical Cyclone Report.'' May 9, 2018. *https://www.nhc.noaa.gov/data/tcr/AL092017_Harvey.pdf.*

[57] Richard J. Pasch, Andrew B. Penny, and Robbie Berg. NOAA National Hurricane Center. ''National Hurricane Center Tropical Cyclone Report: Hurricane Maria.'' February 14, 2019. At page 7. *https://www.nhc.noaa.gov/data/tcr/AL152017_Maria.pdf.*

[58] PHMSA, ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration,'' 84 FR 14715 (Apr. 11, 2019) (Advisory Bulletin ADB–2019–01).

[59] PHMSA, ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards,'' 84 FR 18919 (May 2, 2019) (Advisory Bulletin ADB–2019–02).

[60] PHMSA, ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards,'' 87 FR 22576 (June 2, 2022) (Advisory Bulletin ADB–2022–01).

[61] PHMSA, ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes,'' 76 FR 54531 (Sept. 1, 2011) (Advisory Bulletin ADB–11–050).

[62] U.S. Global Change Research Program, *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment—Executive Summary* at 6 (2016).

[63] U.S. Global Change Research Program, *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment* at 21 (2016).

[64] *See* Emanuel et al., ''Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States,'' 5 *GeoHealth* (June 2021).

pipeline at some stage of its lifecycle. PHMSA is, by statute (49 U.S.C. 60101 *et seq.*), responsible for regulating the interstate transportation of gas by pipeline facilities, which can include the gathering, transmission, and distribution of natural gas as well as other gases regulated under parts 191 and 192.[65] Federal law, however, provides that the certified State agencies have jurisdiction to regulate purely intrastate gas pipeline facilities. Certain certified State programs may also inspect interstate pipelines, such as interstate distribution systems. Both Federal and State regulation of gas pipeline facilities has historically been directed toward the immediate, direct risks to public safety (and indirect risks to the environment) associated with the ignition of natural gas releases—less so on the direct threat to environmental risks, including those risks posed by un-ignited, released methane, that invariably contribute to climate change.[66]

1. Gas Pipeline Facilities

PHMSA regulations cover several types of gas pipeline facilities, including gas gathering pipelines, gas transmission pipelines, gas distribution pipelines, LNG facilities, and UNGSFs.

Gathering Pipelines

A gas gathering pipeline is defined in Federal regulations at § 192.3 as a pipeline that transports gas from a production facility to a transmission pipeline or main. More generally, these pipelines ''gather'' gas from production facilities for transport to a gas processing plant for further transportation across transmission pipelines. The precise points where a gathering pipeline begins and ends are defined in §§ 192.8 and 192.9 and the first edition of American Petroleum Institute (API) Recommended Practice 80, ''Guidelines for the Definition of Onshore Gas Gathering Lines.'' [67]

Section 192.9(b) provides that offshore gas gathering pipelines are generally subject to the same part 192 requirements as gas transmission pipelines. Section 192.8 also defines three types of regulated onshore gas gathering pipelines subject to part 192 requirements: Type A, Type B, and Type C gathering pipelines. Operators reported 8,290 miles of Type A pipelines, 3,078 miles of Type B pipelines, and 5,706 miles of offshore gathering lines in their 2021 annual reports. Type C gathering line operators will be required to submit their first annual report for calendar year 2022 in 2023; PHMSA estimates that there are approximately 90,000 miles of Type C gathering lines.[68] Type A and Type B gathering pipelines are located in Class 2, Class 3, or Class 4 locations. Type A gathering pipelines are higher-pressure pipelines and subject to most part 192 safety requirements applicable to gas transmission pipelines, while Type B gathering pipelines are lower pressure pipelines subject to a smaller subset of specific part 192 safety requirements listed in § 192.9(d). The Type C gathering pipeline designation was established in a final rule titled ''Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation or Large, High-Pressure Lines, and Other Related Amendments'' published on Nov. 15, 2021.[69] Type C gathering pipelines are located in Class 1 locations, have an outside diameter greater than or equal to 8.625 inches, and operate at high pressure.[70] These pipelines are subject to scaled safety requirements in § 192.9(e), with more part 192 safety requirements applicable as a function of the risk posed to public safety based on the diameter of the Type C segment (which affects the potential energy of a pipeline rupture and explosion) and its proximity to nearby populated structures. For example, § 192.9(e) provides that while all Type C lines are required to carry out a damage prevention program, leakage survey requirements only attach to either the largest (outside diameter greater than 16 inches) Type C lines, or those Type C lines with smaller diameters (8.625 inches through 16 inches) near buildings intended for human occupancy.

Type A, Type B, and certain Type C gathering pipelines (namely, those Type C gathering pipelines that are installed, replaced, relocated, or otherwise changed after May 16, 2023) must comply with the design, construction, initial inspection, and initial testing requirements applicable to gas transmission lines, and must therefore be constructed from similar materials. According to annual reports submitted to PHMSA, gas transmission pipelines and Type A and Type B regulated onshore gathering lines are generally made from steel and, to a lesser extent, polyethylene plastic. An operator may also use two polyamide compounds, PA–11 and PA–12. Composite materials [71] may be used with notification to PHMSA on a Type C gathering pipeline. PHMSA expects that most Type C gathering pipelines, which have operational characteristics similar to gas transmission and Type A regulated gas gathering pipelines, are made of steel, but Type C pipelines existing prior to May 16, 2023, may have been constructed with non-standard materials.

Transmission Pipelines

A gas transmission pipeline is defined in § 192.3 to include any pipeline, other than a gathering pipeline, that transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large-volume customer such as a gas power station or an LNG facility. In 2021, operators reported 301,524 miles of gas transmission pipelines on their annual reports. Additionally, a pipeline other than a gathering pipeline that operates at a hoop stress of 20% or more of the specified minimum yield strength (SMYS),[72] or that transports gas within a storage field, is also classified as a gas transmission pipeline. An operator may also voluntarily designate a pipeline as a gas transmission pipeline that would otherwise meet the definition of a gas gathering pipeline or gas distribution

[65] Parts 191 and 192 govern not only natural gas, but also any ''flammable gas, or gas which is toxic or corrosive.'' *See* §§ 191.3 and 192.3 (definitions of ''gas''). Consequently, the proposed revisions to parts 191 and 192 within this NPRM would apply not only to natural gas pipelines but also to other gas pipeline governed by parts 191 and 192.

[66] PHMSA acknowledges that in revising its Pipeline Safety Regulations over the years, it has identified environmental benefits of those efforts in much the same way that it has identified other benefits (*e.g.,* reduced compliance cost for operators, equity, etc.) of those rulemakings. However, PHMSA submits those non-safety benefits were generally presented as secondary benefits of safety-focused regulatory amendments.

[67] API, *Recommended Practice 80: Guidelines for the Definition of Onshore Gas Gathering Lines* (Apr. 2000) (API RP 80).

[68] *See* PHMSA, Doc. No. PHMSA–2011–0023, ''Regulatory Impact Analysis: Pipeline Safety: Expansion of Gas Gathering Regulation Final Rule'' at 11, 15 (Nov. 2021) (Gas Gathering RIA).

[69] 86 FR 63266 (Gas Gathering Final Rule). Certain smaller-diameter Type C gas gathering pipelines are the subject of a temporary enforcement discretion whereby PHMSA has committed not to pursue enforcement action against those pipelines for alleged violations of certain part 192 safety requirements before May 17, 2024. *See* 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.*

[70] See the pressure criteria in the second column of table 1 in § 192.8(c)(2).

[71] ''Composite materials'' are defined in § 192.3 as materials used to make pipe or components manufactured with a combination of either steel and/or plastic and with a reinforcing material to maintain its circumferential or longitudinal strength.

[72] SMYS is defined in 49 CFR 192.3 to mean specified minimum yield strength, which is a measure of tensile strength. As an example, Trade B pipe made to API 5L specification has a specified minimum yield strength (SMYS) of 35,000 pounds per square inch (psi) 40 percent of SMYS (35,000 × 0.40) is 14,000 psi.

pipeline. Gas transmission pipelines are typically steel, larger diameter (6 to 48 inches), high-pressure lines (operating pressures generally between 200 and 1500 pounds per square inch) transporting large volumes of gas long distances.

Distribution Pipelines

A gas distribution pipeline is defined at § 192.3 as a pipeline other than a gas transmission pipeline or gathering pipeline. Distribution pipelines are typically a part of a distribution system that transports gas received from a transmission pipeline by a distribution center (often located at the so-called ''city gate''), and then to homes and businesses through a network of gas mains and service pipelines.[73] A gas distribution service pipeline feeds gas to one or two customers, while a distribution main is the common source of supply for two or more service pipelines. In 2021, distribution operators reported 2,300,793 miles of gas distribution mains and service lines on their annual reports. While virtually all gas transmission piping is fabricated from steel, gas distribution pipeline materials vary depending on the vintage and usage. Modern systems are predominately polyethylene plastic and protected steel (*i.e.,* coated with corrosion-resistant materials and/or equipped with cathodic protection); older systems may contain cast-iron or bare (not protected) steel piping. Distribution pipelines made of copper, wrought iron, and non-polyethylene plastic also exist but are less common.

LNG Facilities

An LNG facility is defined in Federal regulations at 49 CFR part 193 [74] as a gas pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing LNG. LNG means natural gas or synthetic gas having methane as its principal constituent, and which has been changed to a liquid, thereby reducing the volume of the gas to facilitate storage and long-distance transportation. LNG facilities are subject to the safety requirements in part 193. LNG facilities include gas pipeline facilities that either change gas into LNG (liquefaction) or that change LNG back into a vapor or gaseous state (vaporization). LNG facilities also include transfer piping systems that transfer LNG between any of the following: liquefaction process facilities, storage tanks, vaporizers, compressors, cargo transfer systems, and facilities other than gas pipeline facilities. In 2021, operators reported 168 in-service LNG facilities on their annual reports.

Underground Natural Gas Storage Facilities

Finally, an UNGSF is defined at § 192.3 as a gas pipeline facility that stores natural gas underground incidental to the transportation of natural gas, including: (1) a depleted hydrocarbon reservoir; (2) an aquifer reservoir; or (3) a solution-mined salt cavern. In addition to the storage reservoir or cavern itself, an UNGSF includes: injection, withdrawal, monitoring, and observation wells; wellbores and downhole components; wellheads and associated wellhead piping; wing-valve assemblies that isolate the wellhead from connected piping beyond the wing-valve assemblies; and any other equipment, facility, right-of-way, or building used in the underground storage of natural gas. Most underground natural gas storage occurs in depleted natural gas reservoirs. UNGSFs are subject to specific safety requirements set forth in § 192.12.

2. Sources of Emissions From Gas Pipeline Facilities

Emissions of methane and other gases subject to PHMSA's regulations under part 192 occur in all sectors of the natural gas industry—from production/extraction facilities, gathering pipelines, processing facilities (where the gas is made suitable for transportation and use), transmission pipelines, distribution pipelines, and end user facilities.[75] Emissions occur during normal operation, routine maintenance, and abnormal conditions (such as incidents). Gas pipeline facilities emit methane and other gases from ''fugitive emissions'' from system upsets (incidents and abnormal operations that result in the release of gas); unintentional leaks from line pipe, flanges, valves, meter sets, and other equipment; and intentional releases (such as when a gas pipeline facility is blown down for repairs or maintenance or through pressure relief device operation as designed or configured). Older pipelines and pipelines known to leak based on their material (*e.g.,* legacy materials such as cast iron, wrought iron, unprotected steel, and certain historic plastics), design, or past operating and maintenance history are generally more susceptible to leaks.

The EPA compiles and publishes data on the magnitude and sources of methane emissions from gas gathering, transmission, and distribution pipelines and other gas pipeline facilities. The EPA has two complementary programs for characterizing GHG emissions such as methane: the Inventory of Greenhouse Gas Emissions and Sinks (Greenhouse Gas Inventory, or GHGI), and the Greenhouse Gas Reporting Program (GHGRP).

- The 2022 GHGI estimates a time series of total annual national-level GHG emissions across sectors of the economy using a large number of data inputs including GHGRP, research studies, and national and subnational activity data sets. The most recent final GHGI (2022 GHGI) includes estimates from 1990 through 2020.[76] The GHGI includes estimates of GHG emissions from sources including fossil fuel combustion, industrial processes, agriculture, and transportation. The GHGI is updated annually.
- The Greenhouse Gas Reporting Program (GHGRP) has, since 2010, collected facility-level emissions data from certain large GHG emission sources, fuel and industrial gas suppliers, and CO_2 injection sites in the United States including large suppliers or facilities that emit more than 25,000 metric tons of CO_2 equivalent per year.[77]

For the 2020 reporting year, subpart W facilities in the GHGRP included 164 reports from distribution operators and 45 reports from gas transmission pipeline operators. However, GHGRP

[73] Under 49 U.S.C. 60105 and 60106, States may assume safety authority over intrastate gas pipelines through certifications and agreements with PHMSA. Currently, the District of Columbia, Puerto Rico, and all States except Alaska and Hawaii exercise safety oversight authority over all intrastate gas distribution pipelines within State lines. These State programs conduct regular inspections and enforce State safety regulations over intrastate distribution pipelines. *See* PHMSA's State Programs website for more information: *https://www.phmsa.dot.gov/working-phmsa/state-programs/state-programs-overview* (last accessed Dec. 20, 2022).

[74] Part 193 requirements may change as a result of regulatory amendments proposed in a forthcoming notice of proposed rulemaking issued under RIN 2137–AF45. PHMSA's references to part 193 within this NPRM—including the proposed amended regulatory text at its conclusion—reflect current regulatory text and organization.

[75] Although the evaluation of release data discussed in this section II.C.2 and subsequent sections is focused on the location, frequency, and severity of leaks on natural gas pipeline facilities, that analysis is largely applicable to leaks on other part 192-regulated gas pipeline facilities. Indeed, certain part 192-regulated gas pipeline facilities (*e.g.,* gas pipeline facilities transporting hydrogen gas) may be particularly susceptible to leaks because of (inter alia) the smaller size of hydrogen gas molecules compared to methane molecules of which natural gas is mostly composed.

[76] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020* (Apr. 15, 2022) (2022 GHGI).

[77] In the GHGI, the EPA estimates that the global warming potential of 1 metric ton of CH_4 is equivalent to 25 metric tons of CO_2 over a 100-year time horizon. (40 CFR 98, Table A–1 to Subpart A of Part 98).

data is not congruent with the pipelines subject to PHMSA regulations. For example, the 45 gas transmission pipeline operators submitting reports under GHGRP for the 2020 reporting year correspond only to approximately ⅔ of gas transmission pipeline mileage nationwide.[78] Additionally, certain entire sectors, such as the agricultural sector, are not required to report to the GHGRP. The creation of the GHGRP was provided for by Congress in the fiscal year 2008 Consolidated Appropriations Act (Pub. L. 110–161) and promulgated under section 114 of the Clean Air Act.[79] Data must be reported to EPA by March 31 of each year. Petroleum and natural gas industries, including natural gas distribution facilities, onshore natural gas gathering and boosting, onshore natural gas transmission pipelines (including compression), and LNG storage/terminal facilities are covered under 40 CFR part 98, subpart W.

The GHGI estimates for methane emissions are generally developed by multiplying an emissions factor by an activity factor. For example, for distribution main leaks, an emission factor in kg CH_4 per mile by material type is multiplied by mileage data by material type (an activity factor) from PHMSA annual reports. Each itemized emissions segment or source in the GHGI has its own emissions factor, in many cases derived from GHGRP data. EPA annually updates the methodology in the GHGI to improve accuracy and completeness.[80] The current GHGI quantifies emissions from leaks in pipelines using the following approaches and data:

- Gathering pipeline leaks. Emission factors are developed using year specific GHGRP data. GHGRP data are used as the activity factor as well. GHGRP data are reported by material type.
- Transmission pipeline leaks. Data from EPA/GRI 1996 were used to develop the emission factor. PHMSA mileage data are used as the national activity factor.
- Distribution pipeline leaks. Data from Lamb et al. 2015 were combined with EPA/GRI 1996 to develop the material-specific emission factors. PHMSA main mileage and service line count data are used as the national activity factor, by material type.

Recent research using modern leak detection equipment indicates that overall fugitive methane emissions from gas pipeline facilities may be significantly underestimated in current methane emissions estimates. The methodology of multiplying an activity factor (such as pipeline mileage) by an emissions factor to extrapolate an estimate of overall emissions for a given source is considered a ''bottom-up'' approach that can be contrasted with a ''top-down'' approach taking total emissions measured at larger (*e.g.,* national) scales and attributing emissions to specific sources through modeling. Top-down approaches regularly estimate higher total emissions in the atmosphere than have been estimated by bottom-up approaches (sometimes referred to as the ''top-down/bottom-up gap''). For example, recent analysis using top-down methods from the International Energy Agency (IEA) released in early 2022 found that global methane emissions from the energy sector are about 70% greater than the official statistics reported by national governments.[81] IEA used satellite-based sensor technologies, atmospheric methane measurements, and data processing techniques to capture total emissions over large areas and attribute those emissions to facility-level sources, rather than by simply multiplying activity factors by bottom-up emissions factors. Other studies comparing the two approaches have consistently shown that bottom-up approaches may underestimate total U.S. methane emissions by 50% or more.[82] One explanation suggested for the significant discrepancy in estimated emissions is that bottom-up methods under-sample large but infrequent emissions events such as malfunctions and venting, possibly due to the difficulty and risks associated with taking samples during such events.[83] Furthermore, as discussed below, recent research also indicates that potential under-estimation of pipeline facility emissions could be particularly pronounced in connection with distribution and gathering pipelines. EPA has recently proposed adjustments to its GHGRP data collection for reporting equipment leaks from natural gas distribution sources (including pipeline mains and services, below grade transmission-distribution transfer stations, and below grade metering-regulating stations) and for reporting emissions from equipment at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.[84] Additional discussion of emissions factors for gas pipelines is available in the Preliminary RIA for this NPRM available in the rulemaking docket.

Methane Emissions Data—All Natural Gas Pipeline Facilities

The 2022 GHGI estimated annual net methane emissions from U.S. natural gas systems in 2020 to be 6,6,137 thousand metric tons (kt).[85] Gas transmission, gas distribution, transportation-related gas and LNG storage, and regulated gas gathering lines as determined in § 192.8 are regulated by PHMSA. On the other hand, exploration, production, gas processing plants, and Type R unregulated gas gathering lines are not regulated by PHMSA.). Assuming approximately one third of gathering and boosting emissions are attributable to regulated gas gathering lines, approximately half of net methane emissions from natural gas systems are from PHMSA-regulated pipeline facilities. The sector classifications used in the GHGI may not correspond precisely with the regulatory definitions of different types of pipeline facilities in the Federal Pipeline Safety Regulations. In EPA's GHGI, the gathering and

[78] One operator may submit multiple GHGRP reports if they operate multiple systems or in multiple states.

[79] 42 U.S.C. 7414.

[80] Refer to tables 3.6–2, 3.6–6, and 3.6–17 of Annex 36 of the 2022 GHGI for more information on the methodologies or data sources used by EPA to develop each emissions factor.

[81] IEA, Press Release, ''Methane emissions from the energy sector are 70% higher than official figures'' (Feb. 23, 2022), *https://www.iea.org/news/methane-emissions-from-the-energy-sector-are-70-higher-than-official-figures.* IEA's analysis may underestimate the full extent of methane emissions as satellite data used by the organization do not provide complete coverage of all global oil and gas operations.

[82] Zavala-Araiza et al., ''Reconciling Divergent Estimates of Oil and Gas Methane Emissions,'' 112 *Proceedings of the National Academy of Sciences of the United States of America* 11597–98 (Dec. 22, 2015); Lyon et al., ''Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region,'' 49 *Environmental Science & Technology* at 8147, 8154 (July 7, 2015); Alvarez et al., ''Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain,'' *Science* 186 (June 21, 2018).

[83] Brandt et al., ''Methane Leakage from North American Natural Gas Systems,'' *Science* 343, 345 (Feb. 13, 2014); Zavala-Araiza et al., 2015, at 15598; Lyon, at al., 2015, at 8147, 8155; Alvarez et al., 2018, at 183. The authors of the Brandt, Zavala-Araiza, and Lyon studies also suggest that this underestimation of emissions could be due to (or exacerbated by) incomplete activity factors that omit certain emissions source activities (such as inaccurate component counts or even the omission of entire facilities). Further, the authors of the Brandt study point to limited sample sizes and changing technologies as other potential sources of error in bottom-up emissions estimates.

[84] EPA, ''Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule—Notice of Proposed Rulemaking'' 87 FR 36920, 36927 (June 21, 2022).

[85] Natural gas systems include exploration, production, gathering, processing, transmission, storage, and distribution of gas. The 2022 GHGI inventory introduced estimates of post-meter emissions. Emissions from power generation are estimated elsewhere in the GHGI.

boosting sources include gathering and boosting stations (with multiple sources on site) and gathering pipelines. Those sources include PHMSA-regulated gas gathering lines, Type R gathering lines, and some pipelines and activities that are better described as production and not transportation.[86] The GHGI data cited in this section is for natural gas systems, and therefore would be covered under the regulatory classifications in part 192. The EPA definition is similar in principle to the definition of a gas ''gathering line'' in part 192, although it references some gas treatment processes that could be classified as a ''production operation'' rather than as a gathering pipeline under § 192.9 and the first edition of API RP 80, and therefore not under PHMSA's jurisdiction. However, for the purposes of estimating emissions from leaks and incidents on PHMSA-regulated gas gathering pipelines, PHMSA believes that the emissions rate associated with ''pipeline leaks'' from ''gathering and boosting'' piping as defined by EPA would not be significantly different than the emissions rate for gas gathering pipelines as defined by PHMSA.

While natural gas exploration and production (*i.e.,* the upstream sector) is the single largest source category, approximately one-third of total methane emissions are attributed to transmission, storage, and distribution systems, and an additional one-fourth of total methane emissions is attributed to natural gas gathering and boosting systems. A summary of these high-level emissions estimates is shown in the table below and represent the net methane emissions [87] for 2020 from section 3.7 and annex 3.6 of the 2022 GHGI. These figures represent only methane emissions and do not include, for example, CO_2 emissions from compressor station engines.

2022 GHGI: 2020 NATURAL GAS SYSTEMS NET METHANE EMISSIONS

Source	Kt CH_4	Percent
Exploration and Production (excluding gathering)	1,964	32
Gathering and Boosting	1,500	24
Processing Plants	494	8
Transmission, Storage, and LNG	1,625	26
Distribution	554	9
Total	6,137	100

Methane Emissions Data—Natural Gas Distribution Pipelines

The GHGI estimates that in 2020, approximately half of methane emissions from natural gas distribution systems was caused by leaks from and incidents on gas distribution line pipe. Leaks from customer meters, meter stations, and regulator stations comprise most of the remaining emissions. Recent studies indicate, however, that current methane emissions data likely significantly under-estimates methane emissions from gas distribution pipelines. For example, a national study focusing on the natural gas distribution sector estimated emissions from mains that were five times larger than those in the GHGI estimate for 2017 estimates (0.69 million metric tons of methane vs. 0.14 million metric tons) [88] and by extension the GHGI estimate for 2020 as well (0.69 million metric tons of methane vs. 0.13 million metric tons).[89] The current methodology for calculating the emissions factors from natural gas distribution main and service pipelines in the GHGI was most recently updated in 2016 [90] and relies on a 1996 report by the U.S. EPA and the Gas Research Institute (GRI) [91] and a 2015 study by Lamb et. al.[92] The 2020 study by Weller et.al. attributed the differences to a larger number of leaks than previously estimated and better quantification of the largest leaks from the distribution sector (so-called ''super-emitter'' leaks), which contribute significantly to overall emissions.[93]

2022 GHGI: 2020 NATURAL GAS DISTRIBUTION SYSTEMS EMISSIONS BY CATEGORY

Source	Kt CH_4	Percent
Main Pipeline Leaks	132.0	23.8
Service Pipeline Leaks	70.8	12.8
Mishaps (*e.g.,* Incidents)	68.6	12.4
Meter/Regulator Stations	44.4	8.0
Customer Meters	235.4	42.5
Pipeline Blowdown	2.1	0.4
Relief Device Venting	1.2	0.2
Total	554.5	100

Note the PHMSA definition of a service pipeline in § 192.3 includes the customer meter in most configurations.

[86] 2022 GHGI. Pg. 3–90.

[87] Net emissions estimates include estimated emissions reductions from reported implementation of EPA Methane Challenge and Gas STAR best practices by operators in the production, transmission and storage and distribution sectors and estimated reductions from EPA regulatory requirements.

[88] Weller et al., ''A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems,'' 54 *Environmental Science & Technology* 8958, 8966 (June 10, 2020).

[89] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020, Annex 3.6–1* (Apr. 15, 2022).

[90] U.S. EPA. ''Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2014: Revisions to Natural Gas Distribution Emissions''. Pgs. 10–13. (April 2016). *https://www.epa.gov/sites/default/files/2016-08/documents/final_revision_ng_distribution_emissions_2016-04-14.pdf.*

[91] EPA & Gas Research Institute, *Methane Emissions from the Natural Gas Industry* (June 1996) (the 1996 GRI/EPA Report).

[92] Lamb et al., ''Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States,'' 49 *Environmental Science & Technology* 5161 (Mar. 31, 2015).

[93] Weller et al., 2020, at 8958–59.

Unlike natural gas transmission systems, the GHGI separately estimates emissions from natural gas distribution mains and service pipelines by construction material.[94] PHMSA has monitored trends in legacy pipe materials for years, as these materials pose safety risks.[95] The GHGI data demonstrates that replacing leak-prone pipe, such as aging cast iron, can have a significant effect in reducing methane emissions from gas distribution systems. Despite dramatically increased natural gas production and consumption between 1990 and 2019, methane emissions from natural gas distribution systems have fallen steadily from 1,819 kt CH_4 in 1990 to 554.5 kt CH_4 in 2020 (as quantified by GHGI). This reduction in methane emissions corresponds to a decline in cast-iron and cathodically unprotected steel pipe mileage over the same period. And while cast iron mains currently represent less than 1 percent of total distribution main miles—approximately 18,000 miles of cast iron or wrought iron distribution main remain in place as of 2021—leaks on such facilities account for approximately one-fifth of GHGI's estimated total fugitive emissions from all natural gas distribution mains in 2020. Additionally, PHMSA incident report data shows that cast iron mains are vulnerable to integrity failures resulting in incidents; around 8 percent of the incidents that occurred on gas distribution mains between 2010 and 2021 occurred on cast iron mains. GHGI and PHMSA data, therefore, demonstrates that replacing leak-prone materials on gas distribution pipelines can reduce fugitive emissions and incidents and suggest that similar environmental and public safety benefits could be achieved by upgrading gas transmission and gas gathering pipelines made from materials known to leak. PHMSA and its predecessor agency, the Research and Special Programs Administration (RSPA), have identified replacement of cast iron and bare steel pipe as a policy priority for reducing gas distribution leaks and incidents for over two decades. Further, on November 15, 2021, the Bipartisan Infrastructure Law (Pub. L. 117–57) appropriated $200 million per year for PHMSA's Natural Gas Distribution Infrastructure Safety and Modernization Grants program, which provides grant funding to municipally or community-owned gas distribution pipeline facilities for the purposes of replacing legacy pipeline facilities.[96]

Methane Emissions Data—Natural Gas Transmission and Storage

The GHGI estimates natural gas transmission pipelines in 2020 emitted 1,300 kt of methane emissions, excluding storage; however, the causes are very different than distribution. Leaks from natural gas transmission line pipe represent a small share of emissions estimated in the GHGI: only 3.3 kt of a total 1,504 kt of net methane emissions from the transmission and storage sector. As shown in the table below, vented and fugitive emissions (*i.e.,* leaks) from natural gas transmission compressor stations, compressors, and regulating and metering stations comprise a significant portion of total methane emissions from pipeline facilities. GHGI data on the natural gas transmission and storage segment reflects both onshore and offshore sources.

2022 GHG INVENTORY: 2020 NATURAL GAS TRANSMISSION METHANE EMISSIONS

Source	Kt CH_4	Percent
Pipeline Leaks	3.3	0.3
Pipeline Venting (including blowdowns and upset venting)	221.3	17.0
Station Venting (including blowdowns)	168.9	13.0
Dehydrator Venting	2.6	0.2
Flaring	0.6	0.0
Pneumatic Devices	36.3	2.8
Compressor Station Fugitive Emissions	702.8	54.1
Compressor Exhaust	164.1	12.6
Total	1,300.0	100.0

Note: Pipeline venting includes releases from ruptures and other incidents.

The table below shows emissions from compressor stations on natural gas transmission pipelines in additional detail. Emissions from generators includes emissions from natural gas storage facilities dedicated to a compressor station.

2022 GHG INVENTORY: 2020 NATURAL GAS TRANSMISSION COMPRESSOR STATION METHANE EMISSIONS

Source	Kt CH_4	Percent
Fugitive Emissions	145.1	14.0
Reciprocating Compressor	419.5	40.5
Centrifugal Compressor (Wet Seals)	57.0	5.5
Centrifugal Compressor (Dry Seals)	81.3	7.8
Engine Exhaust	148.8	14.4
Turbine Exhaust	1.6	0.2
Generator Engines (inc. Storage)	13.8	1.3
Generator Turbine (inc. Storage)	0.004	0.0
Station Venting	168.9	16.3

[94] 2022 GHGI, Annex 3.6.

[95] PHMSA, ''Pipe Replacement Background'' (Apr. 26, 2021), *https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/pipeline-replacement-background* (last accessed Dec. 20, 2022).

[96] *See* PHMSA. ''Natural Gas Distribution Infrastructure Safety and Modernization Grants'' (Aug. 2, 2022), *https://www.phmsa.dot.gov/grants/pipeline/natural-gas-distribution-infrastructure-safety-and-modernization-grants* (last accessed Dec. 20, 2022).

2022 GHG INVENTORY: 2020 NATURAL GAS TRANSMISSION COMPRESSOR STATION METHANE EMISSIONS—Continued

Source	Kt CH_4	Percent
Total	1,035.8	100.0

Additionally, the table below shows emissions from natural gas storage facilities.[97]

2022 GHG INVENTORY: 2020 NATURAL GAS STORAGE METHANE EMISSIONS

Source	Kt CH_4	Percent
Station and Compressor Fugitive Emissions	24.5	7.6
Reciprocating Compressors	102.9	32.2
Storage Wells	11.3	3.5
Metering and Regulating (Transmission Interconnect)	75.3	23.5
Metering and Regulating (Farm Taps & Direct Sales)	17.5	5.5
Dehydrator Venting	4.5	1.4
Flaring	1.1	0.4
Engine Exhaust	22.7	7.1
Turbine Exhaust	0.2	0.1
Generators (inc. Transmission)	13.8	4.3
Pneumatic Devices	17.3	5.4
Station Venting	28.9	9.0
Total	319.9	100.0

Though the 2022 GHGI does not track relief and control device releases as a separate emissions source for natural gas transmission and storage facilities, PHMSA incident report data indicates that such releases are a significant contributor to methane emissions. A pressure relief device is designed to allow gas to escape from a pressurized system to protect the system from overpressurization. Relief devices and other pressure control devices are critical to the safe operation of a pipeline system when they function as intended. However, a poorly designed or poorly configured pressure relief device can result in releases of gas to the atmosphere larger than strictly necessary to protect pipeline integrity. Conversely, a relief device or control device that fails to release gas as designed or configured will not provide adequate protection from overpressurization and may rupture, presenting a hazard to public safety and the environment. Between 2010 and 2021, PHMSA incident report data yields that ''malfunction of control/relief equipment,'' including control valves, relief valves, pressure regulators, and emergency shutdown device system failures,[98] was listed as the cause for 30% of incidents and 21% of unintentional gas emissions from reportable incidents on gas transmission pipelines. Approximately 95% of these incidents are reportable due to reported unintentional emissions exceeding 3 MMCF, although these incidents are occasionally reportable because repair costs or other monetary damages exceed the property damage criterion in § 191.3. Out of these 480 incidents, 114 involved the failure of a relief valve. The next most commonly involved component in these failures were emergency shutdown devices, which resulted in 54 incidents over this time period.

Recent studies also suggest that current methane emissions data likely underestimates emissions from natural gas transmission and storage facilities. The emission factor for transmission pipeline leaks in the GHGI is based on volume 9 of the 1996 GRI/EPA Report. The emissions factor is derived from the frequency of leak repairs reported on operators' annual reports to RSPA and self-reported leak measurements from distribution mains, both collected in 1991.[99] The authors of one study noted that the difficulty in accurately measuring abnormal ''super-emitter'' events from natural gas transmission and storage facilities using on-site measurements suggests that bottom-up methodologies underestimate emissions from ''super-emitter'' events, and consequently total emissions.[100] For example, the 1996 GRI/EPA Report relied on limited RSPA incident report data which did not even include a volumetric incident definition criterion as used under current PHMSA reporting requirements.[101] The RSPA incident report form in 1991 similarly did not require operators to provide an estimate of release volume. While current methane emissions data attempts to address this concern by factoring in ''super-emitter'' estimates, this remains a source of uncertainty for any type of point-in-time measurement.[102] Further, certain infrequent but significant incidents at UNGSFs such as the release of 86 billion cubic feet (BCF) of natural gas from the Aliso Canyon facility

[97] The nature and use of tankage as storage incidental to the movement of gas by pipeline dictates whether storage facilities are pipeline facilities subject to the jurisdiction of 49 U.S.C. 60101, *et seq.*

[98] *See* PHMSA, Form F 7100.2, ''Incident Report -Gas Transmission and Gathering System'' at section G6 (May 2022).

[99] EPA & Gas Research Institute, *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines.* (June 1996). Pgs. 38 and 46.

[100] Zimmerle et al., ''Methane Emissions from the Natural Gas Transmission and Storage System in the United States,'' 49 *Environmental Science & Technology* 9374 (July 21, 2015).

[101] *See, e.g.,* RSPA Form F7100.2 (Rev. 3—1984), ''PHMSA Gas Transmission & Gathering Incident Data—mid 1984 to 2001'', available at *https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data* (last accessed Jan. 4, 2023).

[102] *See* Alvarez et al., ''Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain,'' *Science* 186, Table 1 (June 21, 2018) (finding that bottom-up quantifications of methane emissions may underestimate natural gas transmission and storage emissions by nearly 30% when compared with top-down quantifications).

failure in 2015, the release of 6 BCF of natural gas from the Moss Bluff facility in 2004, and the release of 143 BCF of natural gas from the Yaggy storage field in 2001 demonstrate both the uncertainty in estimating methane emissions from UNGSFs and the potential for substantial methane emissions (which in turn result in public safety harms) from such facilities.[103]

Methane Emissions Data—Gathering Pipelines

The GHGI estimates for ''natural gas gathering and boosting'' systems have estimated fugitive emissions from line pipe leaks that are much higher than for natural gas transmission systems. As shown in the table below, the GHGI estimates 126.7 kt of methane emissions from pipeline leaks in natural gas gathering and boosting systems (estimated at 381,909 miles in the GHGI) [104] compared with 3.3 kt for natural gas transmission systems (302,252 miles). In the RIA for the 2021 Gas Gathering Final Rule, PHMSA estimated that there were approximately 426,000 miles of unregulated rural gas gathering pipelines,[105] in addition to the 17,064 miles of regulated offshore and onshore Type A and Type B regulated gas gathering pipelines reported by operators in 2021. Additionally, the EPA mileage estimate may include mileage that could be considered under § 192.8 to be production pipelines rather than gathering pipelines. The EPA mileage therefore provides an estimate of gathering pipeline mileage and resulting total emissions estimates from such facilities that may not accurately represent emissions from the subset of PHMSA-regulated gathering pipeline sources.

2022 GHG INVENTORY: NATURAL GAS GATHERING AND BOOSTING METHANE EMISSIONS

Source	Kt CH_4	Percent
Station Combustion Slip	407.1	27
Station Compressors	306.9	20
Station Tanks	244.3	16
Station Pneumatic Devices	202.0	13
Pipeline Leaks	126.7	8
Station Yard Piping	93.3	6
Station Blowdowns	44.9	3
Station Dehydrator Vents and Leaks	25.7	2
Station Pneumatic Pumps	27.2	2
Pipeline Blowdowns	9.4	1
Station Flare Stacks	11.1	1
Station Separators	1.4	0
Station Acid Gas Removal Units	0.1	0
Total	1500.0	100

Note: Total includes Type R gas gathering pipelines and production operations not regulated under part 192.

Recent research also suggests that, as in the case of other gas pipeline facilities, current methane emissions data likely understates emissions from natural gas gathering pipelines. One study conducted in the New Mexico Permian Basin in 2022 estimated emissions from natural gas production and gathering facilities in that region that were 6.5 times larger than GHGI estimates.[106] In the study, methane emissions were estimated using a comprehensive aerial survey spanning 35,923 square kilometers (including over 15,000 kilometers of natural gas pipelines) over 115 flight days. This large sample size was intended to better capture infrequent ''super-emitter'' events, and the study found that 50% of observed emissions were attributable to large emissions sources with average methane emissions rates greater than 308 kilograms per hour. Even as studies in the past few years have increasingly sounded the alarm that leaks from gathering pipelines and boosting stations are significant contributors to climate change, GHGI emissions factors for those facilities have *decreased* over the same time period due to changes in GHGRP inputs.[107] Moreover, studies aiming to improve gas gathering pipeline emissions factors with more accurate data (like one conducted on the Utica Shale in 2020) [108] suggest that self-reported emissions information from GHGRP reporting on which GHGI emissions data for gathering pipelines is based may underestimate actual emissions rates. Any point-in-time measurement of methane emissions can miss large but infrequent events (particularly methodologies that use smaller sample areas such as ground-based approaches), thus underestimating total emissions when used to extrapolate beyond the sample area to an entire region.[109]

[103] PHMSA, ''Pipeline Safety: Safe Operations of Underground Storage Facilities for Natural Gas,'' 81 FR 6334 (Feb. 5, 2016) (Advisory Bulletin ADB–2016–02).

[104] 2022 GHGI, Annex 36 Table 3.6–7.

[105] Gas Gathering RIA at 15; PHMSA, ''Annual Report Mileage for Natural Gas Transmission and Gathering Systems.'' (Aug. 1, 2022), *https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems* (last accessed Aug. 19, 2022).

[106] Chen et al., ''Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey,'' 56 Environmental Science & Technology 4317 (Mar. 23, 2022) (finding that ''[m]idstream assets were also a significant source [of emissions], with 29 ± 20 t/h [(metric tonnes per hour)] emitted from pipelines (including underground gas gathering pipelines) and 26 ± 16 t/h emitted from compressor stations without a well on site'').

[107] GHGI emissions factors for gathering pipeline leaks were identified as 354.7 CH_4/mile in 2017 but decreased to 288.5 in the 2022 GHGI. *See* 2022 GHGI, Annex 36 Table 3.6–2. *See also* Li et al., ''Gathering Pipeline Methane Emissions in Utica Shale Using an Unmanned Aerial Vehicle and Ground-Based Mobile Sampling,'' *Atmosphere* (July 5, 2020) (calling for improved gas gathering pipeline methane emissions factors for the Utica Shale region based on data from both aerial surveys and ground-based vehicle sampling); Chen et al., 2022, at 4317–18 (observing that, while ''uncertainty remains about the emissions rates in the Permian Basin'', recent studies conducted in that region ''consistently find emissions significantly in excess of government estimates'').

[108] Li et al., ''Gathering Pipeline Methane Emissions in Utica Shale Using an Unmanned Aerial Vehicle and Ground-Based Mobile Sampling,'' *Atmosphere* (July 5, 2020).

[109] Chen et al., 2022, at 4321–22 (''[T]he clear impact of large emissions found by this study suggests that estimates from ground-based methane surveys may be underestimating total emissions by missing low-frequency, high-impact large emissions.'').

Methane Emissions Data—LNG Facilities

As shown in the tables below, the GHGI estimates that blowdowns account for 80 percent of estimated methane emissions from LNG storage facilities, and nearly half of methane emissions from all LNG facilities.

2022 GHG INVENTORY: LNG STORAGE FACILITY 2020 METHANE EMISSIONS

Source	Kt CH_4	Percent
Equipment Leaks, Compressors, Flares, etc	1.4	13
Blowdowns	8.4	80
Engine Exhaust	0.6	5
Turbine Exhaust	0.1	1

2022 GHG INVENTORY: LNG IMPORT TERMINAL 2020 METHANE EMISSIONS

Source	Kt CH_4	Percent
Equipment Leaks, Compressors, Flares, etc	0.1	22
Blowdowns	0.2	33
Engine Exhaust	0.2	45
Turbine Exhaust	0.0	<1

2022 GHG INVENTORY: LNG EXPORT TERMINAL 2020 METHANE EMISSIONS

Source	Kt CH_4	Percent
Equipment Leaks, Compressors, Flares, etc	4.0	53
Blowdowns	0.3	4
Engine Exhaust	1.4	18
Turbine Exhaust	2.0	26

Fugitive emissions represent the majority of estimated methane emissions from LNG import and export terminals. While LNG facilities are often designed with boil-off gas recovery systems to avoid routine continuous venting of natural gas during operations, methane regularly escapes from LNG facilities through compressor rod packing and valve leakage, incomplete combustion during flaring, and other various process venting sources.[110] Similar to gas transmission facilities, additional emissions are attributable to releases from relief devices and O&M related venting. Likewise, fugitive emissions from gas treatment equipment at liquefaction plants are likely similar to those from comparable equipment on other pipeline or gas processing facilities.[111] Methane may also be lost to the atmosphere during pipe transfers of LNG to or from an LNG facility, whether through loading for transport or off-loading for storage or vaporization. Even if initially captured, boil-off gas and other fugitive emissions from LNG facilities may still be vented directly to the atmosphere without combustion during normal operation.[112] And, as with any pipe transporting natural gas, the pressurized piping that runs throughout LNG facilities is susceptible to integrity failures and other incidents,[113] including pipeline leaks that can precipitate explosions.[114] For example, Cheniere reported that the Sabine Pass LNG terminal constituted approximately 40 miles of plant piping for its import facilities and an additional 285 miles of plant piping for its first four of six liquefaction trains,[115] and the operator of the Cameron LNG terminal reported approximately 255 miles of piping in their liquefaction project consisting of three liquefaction trains.[116] In addition, Freeport LNG similarly reported its liquefaction project's pretreatment and three liquefaction trains included approximately 192 miles of plant piping, providing ample opportunities for methane to escape during normal and emergency operations.

However, emissions for LNG facilities have proven difficult to estimate due to the limited availability of accurate, complete emissions data, with insufficient differentiation between intentional and fugitive emissions.[117]

[110] API, *Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry* at 6–121 through 6–126 (Nov. 2021).

[111] API, *Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry* at 6–121 through 6–122 (Nov. 2021).

[112] API, *Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry* at 6–123 (Nov. 2021). For example, boil-off gas may be vented if the vapor generation rate exceeds the capacity of the boil-off gas compressors or the re-liquefaction unit. API's compendium estimates typical losses at 0.05% of total tank volume per day when boil-off gas is vented from an LNG storage vessel. *See also* Soraghan & Lee, ''LNG explosion shines light on 42-year-old gas rules'' *EnergyWire.* (June 28, 2022), *https://www.eenews.net/articles/lng-explosion-shines-light-on-42-year-old-gas-rules/* (noting that an LNG terminal had reported several natural gas releases to the state Department of Environmental Quality, including one release of 180,000 pounds of methane in January 2022).

[113] *See, e.g.,* PHMSA, CPF No. 4–2022–051–NOPSO, ''In the Matter of Freeport LNG Development LP: Notice of Proposed Safety Order'' at 3 (June 30, 2022), (describing the LNG release and natural gas vapor cloud that resulted from the June 8, 2022 incident at the Quintana Island LNG facility, which may have been caused by the overpressure and rupture of a segment of LNG transfer line between the facility's LNG storage tank area and its dock facilities).

[114] *See, e.g.,* ''Algerian LNG Complex Explosion Caused by Gas Pipeline Leak,'' *Oil & Gas Journal* (Feb. 18, 2004). A gas pipeline leak was ultimately determined to be the cause of the Skikda, Algeria LNG terminal explosion on January 20, 2004, that killed 27 people, injured 74 others, and resulted in an estimated $800 million–$1 billion in damages to the Skikda port facilities, including the destruction of three of the LNG terminal's six liquefaction trains. *See also* Romero, ''Algerian Explosion Stirs Foes of U.S. Gas Projects,'' *New York Times* (Feb. 14, 2004).

[115] Cheniere. ''Cheniere Energy Analyst/Investor Day.'' (Apr. 2014). Pgs. 12–13.

[116] Cameron LNG. *https://cameronlng.com/lng-facility/economic-impact/.*

[117] Oxford Institute for Energy Studies, *Measurement, Reporting, and Verification of Methane Emissions from Natural Gas and LNG*

Continued

Bottom-up methodologies for estimating LNG emissions typically use generalized emissions factors averaged across the entire sector despite significant differences between suppliers and each step of the supply chain.[118] Emissions estimates using this approach may apply a single emissions factor to all types of LNG facilities, even though the wave of recently built LNG export terminals could have little in common with an LNG peak shaver or storage facility. Developing accurate emissions estimates is also hampered by selection bias. Specifically, EPA currently uses data reported in accordance with 40 CFR part 98, subpart W (*i.e.,* GHGRP) to develop GHGI emissions factors for LNG facilities (with the exception of LNG storage facility blowdowns). However, operators of LNG facilities need only report emissions under subpart W if total emissions reach the reporting threshold of 25,000 metric tons of CO_2 equivalent per year. Many LNG storage facilities fall under that threshold, introducing uncertainty into aggregate emissions calculated using only a subset of LNG storage facilities.[119]

Further, even among those LNG facilities that report their emissions to EPA, there is a potential for great variation in emissions reported within and across reporting years due to small sample sizes: the small number of LNG facilities reporting emissions to EPA (only 5 storage facilities and 11 import and export facilities as of August 2022 [120]) make resulting methane emissions estimates susceptible to substantial year-to-year fluctuation and limit the predictive value of such estimates for subsequent years.[121] Lastly, operators of LNG storage facilities are not required to report LNG storage blowdown emissions under GHGRP—instead, GHGI estimates for LNG storage blowdown emissions consist of generalized data based on a 1996 study of blowdown emissions on gas transmission compressor stations and UNGSFs.[122]

D. The Need for Updating PHMSA Regulations To Incorporate Advanced Leak Detection Programs To Reduce Unintentional Releases From Gas Pipelines

PHMSA's regulations have historically prioritized addressing public safety risks posed by ignition of instantaneous, large-volume releases or accumulated gas. This focus on public safety is vital and can support PHMSA's renewed and expanded commitment to addressing environmental risks as well. However, current regulations can allow leaks of methane and other gases from gas gathering, transmission, and distribution pipeline facilities to continue undetected and unrepaired for extended periods of time.[123] This approach therefore foregoes the emissions reduction potential of commercially available, advanced leak detection technologies and practices within integrated ALDPs. This historical approach also forgoes opportunities for timely identification and remediation of leaks from gas pipelines that can develop into catastrophic incidents. State and voluntary industry efforts to improve leak detection and repair on gas pipelines are emerging, but are insufficient to reduce unintentional emissions of methane and other gases without PHMSA regulations that support and backstop those efforts.

1. PHMSA Regulations Pertinent to Unintentional Releases of Methane and Other Gases

PHMSA's current regulatory requirements pertaining to gas pipeline leak detection, repair, maintenance, and reporting reflect a focus on public safety risks from ignition of instantaneous, large-volume releases or accumulated gas while treating risks to the environment as less important. PHMSA maintenance requirements at part 192, subpart M explicitly require only a subset of unintentional releases from gas pipelines—namely those unintentional releases thought to create an actual or probable harm to public safety—need be identified, repaired, or reported. Nor do those maintenance requirements in the subpart M regulations include explicit requirements for the replacement or remediation of pipes known to leak based on material, design, or past operating and maintenance history.[124] And PHMSA IM regulations at part 192 subparts O (gas transmission pipelines) and P (gas distribution pipelines) allow considerable operator discretion in determining which leaks merit repairs and the timing of those repairs. PHMSA reporting requirements at part 191 similarly are calibrated to provide information regarding instantaneous, large-volume releases rather than granular data on operator leak detection and repair efforts, or the releases of gas from those leaks.

Gas Pipelines Generally

Part 192, subpart M contains minimum maintenance requirements for gas gathering, transmission, and distribution pipelines.[125] Gas transmission (§ 192.706), distribution (§ 192.723), offshore gas gathering, and Type A, Type B, and certain Type C gathering (§§ 192.9 and 192.706) pipeline operators must perform periodic leakage surveys. When leaks are discovered, both their severity and the operating conditions of the pipeline are used to determine whether and when a repair is performed. PHMSA's subpart M requirements contain broad language at § 192.703(c) mandating repair of all ''hazardous leaks . . . promptly.'' However, subpart M neither

Trade: Creating Transparent and Credible Frameworks at 51 (Jan. 2022).

[118] *See* Roman-White et al., ''LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting,'' *ACS Sustainable Chemistry & Engineering* at 10857, 10861 (2021).

[119] EPA, Memorandum, ''Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2017: Updates to Liquefied Natural Gas Segment'' at 2–3 (Apr. 2019). While EPA identified between 94–98 LNG storage facilities as active each year from 2011–2017, only 8 such facilities reported emissions under Subpart W during that timeframe.

[120] *See* EPA, ''GHGRP Petroleum and Natural Gas Systems,'' *https://www.epa.gov/ghgreporting/ghgrp-petroleum-and-natural-gas-systems#emissions-table* (last accessed March 16, 2023).

[121] For example, in 2016, one LNG storage facility was responsible for more than 82% of all LNG storage facility methane emissions and one LNG import terminal was responsible for more than 95% of all LNG terminal methane emissions reported to EPA under Subpart W. EPA, Memorandum, ''Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2017: Updates to Liquefied Natural Gas Segment'' at 3–8 & Tables 5, 8 (April 2019).

[122] EPA, Memorandum, ''Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2017: Updates to Liquefied Natural Gas Segment'' at 1 (April 2019).

[123] PHMSA notes that the limitations of current part 191 and 192 regulations for meaningful and timely identification, repair, and reporting of leaks discussed in this section II.D. may be particularly acute in connection with the pipeline transportation of gaseous hydrogen, which is a much smaller molecule (with potentially greater leakage potential) than methane.

[124] An exception is that part 192, subpart M acknowledges cast-iron piping's susceptibility to leakage and contains provisions focused on a single mechanism (graphitization-derived corrosion) for development of leaks, and then only after indicia of that mechanism have emerged. Specifically, § 192.489(a) requires replacement of each segment of cast iron or ductile iron pipe with general graphitization (a type of corrosion) that could cause a fracture or leak. Section 192.489(b) similarly requires replacement, repair, or internal sealing for localized graphitization on cast and ductile iron pipeline segments that could result in leakage.

[125] Certain part 192 regulations will be revised on codification of a recent PHMSA rulemaking that will become effective on May 24, 2023. *See* PHMSA, ''Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments—Final Rule,'' 87 FR 52224 (Aug. 24, 2022) (RIN2 Final Rule). PHMSA's references to part 192 within this NPRM—including the proposed amended regulatory text at its conclusion—reflect the regulatory text and organization as amended by the RIN2 Final Rule unless otherwise noted. The RIN2 Final Rule contains enhanced repair criteria that can affect leak repairs, but the requirements are generally directed toward phenomena (cracking, corrosion-induced metal loss, dents) distinct from the detection, grading, and repair of all leaks as proposed in this NPRM.

defines a ''hazardous'' leak nor provides guidance on what exactly constitutes a ''prompt'' repair of such leaks. Although § 192.1001 describes a ''hazardous leak'' only in terms of an existing or probable hazard to persons or property (and not the environment), that regulatory definition applies only to the gas distribution system IM requirements in part 192, subpart P. The § 192.703(c) repair mandate is also inapplicable to most Type C gas gathering pipelines.[126]

Part 191 reporting requirements similarly reflect PHMSA's historical focus on public safety risks from ignition of instantaneous, large-volume releases or accumulated gas.[127] Incident reports for gas distribution (Form F7100.1), transmission and part-192 regulated gathering (Form F7100.2), and Type R gathering pipelines (Form F7100.2.2) provide limited information regarding unintentional releases, as only unintentional releases of at least 3 MMCF need be reported. And while annual reports for gas distribution (Form F7100.1–1), transmission and part-192 regulated gathering (Form F7100.2–1), and Type R gathering pipelines (Form F7100.2–3) include information on the number of leaks repaired in the preceding calendar year, the instructions for those annual report forms expressly exclude reporting of repairs on a broad category of leaks: releases that can be corrected by ''lubrication, adjustment, or tightening'' are not considered ''leaks'' for annual reporting of repairs.[128] The instructions for annual reports other than for gas distribution pipelines also do not require reporting of repairs of any leaks other than leaks that are hazardous; and the instructions for all annual report forms characterize leaks as ''hazardous'' with respect to public safety, omitting mention of hazards to the environment. Further, none of PHMSA's annual reports require operators to submit information on either the total number of leaks detected in the reporting period, the rolling tally of all unrepaired leaks, or estimated emissions associated with leaks during the reporting period.

Lastly, only gas transmission pipelines are required to provide geospatial data on their pipeline systems in accordance with the NPMS requirements at 49 U.S.C. 60132 and 49 CFR 191.29. Gas distribution and gathering pipelines have no requirement to provide geospatial data for NPMS.

Part 192—Regulated Gas Gathering Pipelines

Operators of offshore gas gathering, Type A, Type B, and certain Type C gathering pipelines must comply with the leakage survey requirements (at § 192.706) applicable to gas transmission pipelines and repair any hazardous leaks detected (per § 192.703). However, most Type C gathering pipelines—specifically, those with an outer diameter between 8.625'' and 16'' not near an occupied building—are, pursuant to § 192.9(f)(1), not subject to any part 192 leakage survey and repair requirements, whether for ''hazardous'' leaks or any other leaks. Additionally, only offshore gas gathering and Type A gathering pipelines are subject to other subpart M maintenance requirements, including right-of-way patrols (§ 192.705), general transmission pipeline requirements for making permanent or temporary repairs (§ 192.711), and recordkeeping (§ 192.709). Type B and Type C gathering pipelines need only comply with the specific requirements listed in § 192.9(d) and (e), which do not include patrol, repair, and recordkeeping requirements.

Gas Transmission Pipelines

All gas transmission pipelines are subject to maintenance requirements at part 192, subpart M. Section 192.706 requires gas transmission operators to perform leakage surveys on most gas transmission pipelines at least once every calendar year. However, that provision does not require the use of leak detection equipment for those leakage surveys. Leak detection equipment is only required if a gas transmission pipeline is not odorized in accordance with § 192.625 and the pipeline is located in a Class 3 or Class 4 location; otherwise, leak detection can be by human senses only, such as visual observation of dead vegetation or blowing debris. Operators required to conduct a leakage survey with leak detection equipment must do so at least twice each year in Class 3 locations, and at least four times each calendar year in Class 4 locations.

In addition to leakage surveys, § 192.705 requires operators of gas transmission pipelines to have a patrolling program to monitor conditions on and adjacent to pipeline rights-of-way. These patrols are visual surveys, commonly performed using aircraft, and are intended to find leaks and other conditions affecting the safety and operation of the pipeline. Patrols commonly identify potential or current pipeline integrity threats caused by external changes, including construction, excavation, blasting, earth movements, and flooding. Information gathered from these patrols can prevent further damage to the pipeline or target leakage surveys or integrity assessments to locations that may have been damaged. This can prevent leaks, potentially fatal incidents, or damage that could result in shutdowns and maintenance-related releases of methane and other gases to the atmosphere. For example, if an operator spots construction activity along the line, they can dispatch personnel to observe construction to minimize the risk of excavation-related damage to the pipeline. According to incidents reports submitted to PHMSA, such excavation damage is a leading cause of incidents that result in injuries and fatalities and pipeline breaks with very high emissions rates. The patrol frequency depends on the class location of the pipeline, the pipeline's diameter, operating pressure, terrain, weather, and other relevant factors. Gas transmission pipeline operators must perform patrols at least four times each calendar year in Class 4 locations, at least twice each calendar year in Class 3 locations, and at least once each calendar year in Class 1 and Class 2 locations. If the pipeline is located at a highway or railroad crossing in a Class 1 or Class 2 location, the minimum patrol frequency is increased to at least twice each calendar year. In Class 3 locations, the minimum patrol frequency at highway and railroad crossings is four times each calendar year.

As explained above, § 192.703(c) requires all transmission operators to repair leaks that are ''hazardous'' to public safety ''promptly''—but PHMSA regulations contain few guardrails as to what ''promptly'' means. Repair requirements at § 192.711 require that operators take immediate temporary measures for leaks that impair the serviceability of a steel transmission pipeline operating above 40 percent of SMYS if a permanent repair is not feasible.

Section 192.711(b) requires that permanent repair be made as soon as feasible or as specified under the

[126] Only ca. 20,000 miles of the ca. 91,000 miles of Type C gas gathering pipelines are subject to § 192.703(c). PHMSA, Doc. No. PHMSA–2011–0023–0488, ''Regulatory Impact Analysis for Gas Gathering Final Rule'' at 11, 15 (Nov. 2021).

[127] PHMSA annual and incident forms and instructions discussed in this paragraph can be found on PHMSA's website at *https://www.phmsa.dot.gov/forms/operator-reports-submitted-phmsa-forms-and-instructions. https://www.phmsa.dot.gov/forms/operator-reports-submitted-phmsa-forms-and-instructions.*

[128] PHMSA annual reporting requirements for part 193-regulated LNG facilities contain a similar exception from leak reporting requirements. *See* PHMSA, Form 7300.1–3, ''Annual Report Form for Liquefied Natural Gas Facilities (Oct. 2014); PHMSA, Instructions for Form 7300.1–3 at 4 (Oct. 2014) (stating that ''a non-hazardous release that can be eliminated by lubrication, adjustment, or tightening is not a leak'').

operators' IM program under subpart O but does not specify when permanent repairs are necessary.[129] Like the general repair requirement in § 192.703, these requirements frame leak repair obligations in terms of public safety risks and use ambiguous language (''as soon as feasible'') to describe the timing of any repair obligations. In recognition of this regulatory gap, PHMSA has referenced the GPTC Guide in guidance and letters of interpretation on how operators should comply with these provisions of part 192.[130]

Subpart O requirements similarly provide little direction on how gas transmission pipelines that are located in HCAs[131] must manage leak detection and repair, instead giving operators considerable discretion to determine when and how they address leaks on their pipelines. Subpart O requires operators to identify, prioritize, assess, evaluate, repair, and validate the integrity of their pipelines that have the potential to cause injury or death in the event of a failure. In addition, operators must measure IM plan performance to support continual improvement of their programs. Operators of gas transmission pipelines subject to the IM regulations may develop IM plans reflecting idiosyncratic choices regarding identification of specific integrity risks to their pipelines, selection of proper assessment tools; periodic assessment of the pipe for anomalies, and procedures for taking prompt action to address and repair anomalous conditions discovered through pipeline integrity assessments. Additionally, the subpart O regulations do not explicitly require operators to repair all leaks; operators can determine the precise timing of ''prompt'' repairs based on the operator's evaluation of risk to public safety. Further, § 192.93 provides operators up to 6 months from the date that an integrity assessment was performed to confirm discovery of an anomalous condition. Repair criteria at § 192.933 require that anomalous conditions posing the greatest risks to public safety be repaired immediately, but other anomalies that an operator determines pose less significant public safety risks need to be repaired within a year of discovery, or only monitored during subsequent risk assessments and integrity assessments for any change that may require remediation. Section 192.935 directs operators to take additional measures beyond those required elsewhere in part 192 to prevent, and mitigate the consequences of, pipeline failures in HCAs, but that provision identifies enhanced leak detection and monitoring programs as merely one potential item on a menu from which operators may choose in order to meet this requirement.[132]

Gas Distribution Pipelines

Distribution pipelines are subject to select part 192, subpart M maintenance requirements. Section 192.721 requires operators to patrol distribution mains at frequencies that consider the severity of the conditions that would cause failure or leakage, and the consequent hazard to public safety. Distribution mains subject to physical movement or external loading that could fail or leak must be patrolled at least twice each calendar year if located outside of business districts, and at least four times every calendar year if located within business districts. Distribution leakage survey requirements are defined in § 192.723. In business districts, operators must conduct leakage surveys of distribution pipelines with leak detection equipment at least once every calendar year. These surveys must include testing the atmosphere in utility manholes, at cracks in the pavement and sidewalks, and at other locations, providing opportunities to find leaks. Outside of business districts, operators must perform leakage surveys using leak detection equipment as frequently as necessary, but not less than once every 5 calendar years. Gas distribution operators are subject to repair requirements for hazardous leaks at § 192.703, but that requirement provides no specific guidance on repair timelines and fails to mention environmental risks.

The distribution IM program (DIMP) regulations in subpart P require distribution pipeline operators to identify, prioritize, assess, evaluate, repair, and validate the integrity of gas distribution pipelines that have the potential to cause injury or death in the event of a leak or failure. Section 192.1007 requires operators to demonstrate an understanding of their gas distribution systems based on reasonably available information. Operators then must apply the knowledge acquired through reasonably available information to identify threats to the integrity of their gas distribution systems. Threats can include a variety of phenomena: corrosion, excavation damage, vehicular strikes, poorly fitting connections, and other threats. Operators must evaluate and rank the risk to their systems from those threats, and then identify and implement measures to address those risks. DIMP regulations require operators to periodically (at least once every 5 years) evaluate the threats, risks, and results of the performance measures to gauge the effectiveness of their DIMPs in controlling each threat. And § 192.1007(d) explicitly requires distribution pipeline operators to either repair all leaks when found or have an ''effective leak management program.'' However, subpart P prescribes few specific requirements for those leak management programs or criteria for determining their effectiveness, requiring a distribution pipeline operator only to monitor (as a performance measure for evaluating a DIMP), the number of leaks it eliminates or repairs; to categorize such leaks by cause, material; to determine whether they are ''hazardous''; and to report such measures annually to PHMSA. Indeed, the preamble to the 2009 final rule codifying subpart P merely suggested that each operator ''should develop a program based on their knowledge of their pipeline system'' with the GPTC Guide identified as an aid in developing such a program.[133]

[129] The RIN2 Final Rule will amend § 192.711(b) by replacing the existing requirement that permanent repairs of safety-adverse conditions on certain onshore gas transmission pipelines must be made ''as soon as feasible'' with a cross-reference to a new § 192.714 prescribing repair schedules set forth in an industry standard. *See* 87 FR at 52271 (introducing a new § 192.714 referencing ASME/ANSI B31.8S–2004, *Supplement to B31.8 on Managing System Integrity of Gas Pipelines* at section 7, Figure 4 (Jan. 14, 2005)). However, those repair schedules—which are intended for ''anomalies and defects'' consisting of dents, corrosion metal loss, and cracking rather than leaks—contemplate that some repairs may not be required for years. The RIN2 Final Rule does not disturb the existing requirement to effectuate permanent repairs ''as soon as feasible'' for other part 192-regulated gas pipelines not subject to subpart O IM requirements.

[130] *See, e.g.,* PHMSA, ''Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators'' (2013) at 2 (directing larger distribution pipeline operators to refer to GPTC guidelines); PHMSA, Interpretation Response Letter No. PI–93–009 (February 11, 1993) (recommending public stakeholder consult the GPTC Guide for further determination of instruments and techniques to be used in certain leak detection activities); *see also* PHMSA, Interpretation Response Letter No. PI–99–0105 (December 1, 1999) (stating that the GPTC Guide ''is a document endorsed by us which contains information and some methods to assist the gas pipeline operator in complying with the regulations contained in 49 CFR part 192'').

[131] Subpart O contains IM requirements for transmission pipelines in HCAs. Annual reports submitted by operators in 2020 yields that only 7% (ca. 21,000 miles) of the 301,000 miles of gas transmission pipelines are subject to IM requirements at subpart O.

[132] Amendments to subpart O requirements pursuant to the RIN2 Final Rule will not disturb the pertinent requirements of that subpart described above.

[133] PHMSA, ''Pipeline Safety: Integrity Management for Gas Distribution Pipelines—Final Rule,'' 74 FR 63905, 63917 (Dec 4, 2009). PHMSA is undertaking a complementary rulemaking under RIN 2137–AF53 (''Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety

2. Shortcomings of Current PHMSA Regulations in Addressing Unintentional Releases From Gas Pipelines

PHMSA regulations pertinent to leaks from gas pipelines focus on risks to public safety posed by ignition of instantaneous, large-volume releases or accumulated gas from gas pipeline facilities—an approach that is vital for protecting public safety but that foregoes opportunities to address environmental harms, including methane emissions' contribution to climate change. This approach has proven unsuccessful in timely identification and remediation of leaks that can have a substantial impact on the environment or even evolve into incidents posing catastrophic risks to public safety.

As explained above, part 192 subpart M maintenance requirements contain only a single repair requirement specific to leaks, which is applicable only to some part 192-regulated gas gathering, transmission, and distribution pipelines: § 192.703(c)'s requirement that ''hazardous leaks'' be repaired ''promptly.'' However, the term ''hazardous leak'' is nowhere defined in subpart M. Rather, what other limited evidence there is in PHMSA regulations elaborating on the meaning of ''hazardous leak'' pertains either to entirely different elements of part 192 (specifically, the § 192.1001 definition of ''hazardous leak'' within DIMP requirements in subpart P) or part 191 reporting requirements.[134] These regulatory provisions both describe ''hazardous leak'' with respect to potential or present risks to public safety; they are silent regarding risks to the environment.

Similarly, subpart M does not elaborate on the requirement that all hazardous leaks be repaired ''promptly.'' Section 192.711 allows operators to repair hazardous leaks and other conditions as soon as feasible for non-IM repairs, and as prescribed by § 192.933(d) for IM repairs. If a permanent repair is infeasible, § 192.711 merely requires that any temporary measure addresses public safety, again excluding the environment from explicit consideration.

Part 192 nowhere specifies remote or continuous monitoring for pipeline leaks apart from a recent limited requirement pertaining to detection of ruptures (rather than leaks) on certain new gas transmission pipelines with rupture mitigation valves.[135] Frequencies of leakage survey (§ 192.706) and patrol (§ 192.705) requirements are generally keyed to location and the likelihood of nearby people—proxies for risks to public safety but not the environment. Consequently, the majority of part 192-regulated gas transmission and some part 192-regulated, onshore gathering mileage in the United States (in particular, Types A and B gathering pipelines in more populated areas, and a minority of Type C lines[136]) need only have annual leakage surveys, with as long as 15 months between surveys. The default leak detection survey periodicity for gas distribution pipelines outside of business districts is only once every 5 years. Similarly, PHMSA regulations at subpart M allow gas transmission and select part 192-regulated gathering pipeline mileage to have right-of-way patrols only once a year, if at all. Finally, patrols on gas distribution pipelines inside business districts are required twice a year.

Subpart M maintenance requirements governing the use of leak detection equipment also reflect the same historical focus on acute public safety risks. Subpart M regulations are silent on specific technologies or equipment operators should employ in their leak detection surveys. For example, leakage surveys on gas distribution lines, certain regulated gathering lines, and un-odorized transmission pipelines in Class 3 and Class 4 locations must be performed with leak detection equipment—but part 192 neither requires particular technologies, nor establishes performance standards for leak detection equipment. Leakage surveys on other gas transmission pipelines (*e.g.,* odorized lines and all pipelines in Class 1 and Class 2 locations) and patrols of pipeline rights-of-way can rely entirely on human senses such as smell or sight, which are imprecise and substantially limited in their effectiveness. Evidence of a leak detectible by human senses includes dead vegetation caused by natural gas displacing oxygen in the soil, blowing soil, bubbling water, or noise. However, it may take a long time for evidence of a gas leak on vegetation to appear visibly from the air. Further, the reliability of vegetation surveys is inconsistent and depends heavily on soil and climate conditions, the characteristics of the vegetation, the time of year, and other factors. For example, the impacts of gas leaks on vegetation may not be visible during seasonal or climate conditions that produce dead vegetation, and in some soil conditions gas can temporarily increase vegetation growth. Finally, vegetation surveys are ineffective in areas with no or sparse vegetation, such as paved areas, particularly rocky areas, or deserts. PHMSA is not aware of research on the effectiveness of vegetation surveys versus instrumented surveys in general, however operators who begin performing instrumented surveys (such as the aerial survey examples described in section II.D.4) generally report more leaks discovered using instrumented surveys.

Additionally, PHMSA's IM regulations do not require identification and remediation of all leaks. PHMSA's IM regulations apply to about 7 percent of gas transmission pipelines.[137] And no part 192-regulated gathering pipelines (even Types A and C pipelines with operating characteristics and threats to public safety and the environment comparable to transmission lines)[138] are subject to any IM requirements. IM requirements also reflect a historical focus on identifying, preventing, and remediating risks to public safety from large-volume, instantaneous releases or accumulated gas rather than environmental harms. While the gas transmission IM regulations at subpart O oblige some transmission operators to find and eliminate pipeline anomalies posing risks to public safety, those regulations do not require repair of all leaks discovered and allow for substantial delay in the evaluation and subsequent repair of leaks that operators

Initiatives'') responding to congressional mandates in title II of The PIPES Act of 2020 directing PHMSA to, among other things, amend its subpart P distribution IM program requirements. PHMSA expects that the leak detection, grading, and repair requirements for gas distribution pipelines proposed herein would reinforce any changes to subpart P proposed in that rulemaking.

[134] *See, e.g.,* PHMSA, Form F7100.1–1 Instructions (May 2021) (defining hazardous leaks as those representing an ''existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous''). The instructions for annual report forms for other gas pipeline facilities contain similar language.

[135] PHMSA, ''Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards—Final Rule,'' 87 FR 20940, 20985 (Apr. 8, 2022) (introducing a new § 192.636).

[136] Only ca. 20,000 miles of the ca. 91,000 miles of Type C gas gathering pipelines are subject to § 192.706 leakage survey requirements. PHMSA, Doc. No. PHMSA–2011–0023–0488, ''Regulatory Impact Analysis for Gas Gathering Final Rule'' at 11, 15 (Nov. 2021).

[137] The effectiveness of its IM regulations for gas transmission pipelines at subpart O relies on operators' identification that those requirements apply—which is not a given. *See* NTSB, Pipeline Accident Brief 13–01, ''Rupture of Florida Gas Transmission Pipeline and Release of Natural Gas'' (Aug. 13, 2013) (finding that a gas transmission pipeline operator's exclusion of a segment from its IM plan due to mischaracterization of a Class 1 location contributed to a subsequent rupture).

[138] *See* Gas Gathering Final Rule, 87 FR at 6367–68, 63278–79 and 63282–84.

(largely at their discretion) consider not to pose acute public safety risks. DIMP regulations require gas distribution pipeline operators to have an ''effective leak management program,'' but those regulations provide few standards regarding what constitutes an ''effective'' program and can instead give considerable deference to an operator's discretion regarding which leaks are repaired and when. Further, neither subparts O nor P require operator IM plans to consider replacement or remediation as a preventative or mitigative measure for pipe materials known to leak, despite data demonstrating that cast iron, wrought iron, unprotected steel, and certain plastic pipelines are more susceptible to leaks and other losses of pipeline integrity. PHMSA's IM regulations are also not designed to address leaks with low release rates that persist for a long period of time, which can make significant contributions to climate change.

PHMSA part 191 reporting requirements also reflect a narrow focus on public safety risks rather than environmental harms such as the contribution of methane leaks to climate change, or environmental degradation from the release of other flammable, toxic or corrosive gases. Incident reporting requirements are expressed in terms of personal injury, commercial harm, property damage, or minimum release volumes that are far too high (3 MMCF) to capture any but the largest unintentional leaks from pipeline facilities—corresponding to a volumetric release rate of 340 cubic feet per hour (CFH) or more over a one-year period. Although annual reports submitted to PHMSA contain information on all leaks repaired each year, the instructions for those annual reports explicitly discourage reporting of leaks that can be eliminated by ''lubrication, adjustment or tightening'' on the narrow presumption that such releases were not necessarily hazardous from a public safety perspective. Operators are also not required to submit in their annual reports the total number of leaks—of any type—detected in the reporting period; the number of outstanding unrepaired leaks from year-to-year; or estimated emission volumes from any category of detected leaks.

Finally, the exclusion of all gas gathering pipelines from NPMS reporting requirements inhibits PHMSA, State regulators, operators, and members of the public from knowing the location and operating characteristics of pipelines. Such knowledge would help identify and remediate leaks and avoid excavation damage. Although all part 192-regulated gathering pipelines are subject to damage prevention requirements of § 192.614, those requirements are not reinforced by the NPMS requirements identifying the precise location of pipeline infrastructure.

3. Real-World Consequences of Delayed Repair and Prolonged Releases From Leaks on Gas Pipelines

The shortcomings of existing regulations pertaining to leak detection and repair described above are not abstract risks; operators currently allow leaks from gas pipelines to continue emitting methane and other gases for extended periods of time, thereby threatening the environment as well as public safety and human health.

Infrequent leak detection and patrol periodicities provide extended time intervals within which leaks can develop and worsen, thereby resulting in prolonged methane and other emissions to the atmosphere. Infrequent leak detection and patrol periodicities also entail increased public safety risks. Specifically, PHMSA's regulations have long recognized the safety risk associated with potential ignition of leaks, as evidenced by heightened leak surveying and maintenance requirements throughout part 192 for pipelines located in areas where buildings intended for human occupancy are more prevalent (Class 3 or 4 locations) as well as requirements to prevent the accumulation of gas in confined spaces (*see, e.g.,* §§ 192.167(c)(2), 192.353(c), 192.355(b)(2), and 192.361(e)(3)). But leaks on gas pipelines that are not associated with potential ignition of leaks also entail public safety risks. Leaks of toxic or corrosive gases from part 192-regulated pipeline facilities can have serious public safety consequences. And leaks of any type can degrade into catastrophic failures—sometimes referred to as the ''leak-before-break'' concept.[139] Additionally, the absence of baseline leak detection equipment technology requirements for conducting leakage surveys can also inhibit timely opportunities to identify, evaluate, and remediate leaks. The absence (in subparts M, O, and P) of repair criteria and mandatory repair schedules for all leaks compounds the delays and methodological shortcomings in identifying leaks. And PHMSA's limited reporting requirements for leaks from all types of gas pipeline facilities can complicate its ability to identify systemic pipeline integrity issues or support enforcement actions against specific operators. Lastly, the exemption of all gas gathering pipeline facilities from NPMS reporting requirements inhibits timely leak detection and introduces heightened vulnerability to a principal mechanism (excavation damage) for loss of pipeline integrity.

PHMSA further estimates that, due to those limitations in its regulatory regime, thousands of leaks persist across part 192-regulated gas pipelines. With respect to gas distribution pipelines, PHMSA annual report data between 2010 and 2021 yields roughly the same per-mile, nationwide averages of repairs of all leaks (0.225 leaks repaired/mile in 2010 and 0.230 in 2021) and repairs of hazardous leaks (0.089 in 2010 and 0.086 in 2021). PHMSA assumes that the average per-mile rate at which new leaks are created (controlled for material type) remains constant, suggesting either that operators may not be reporting to PHMSA a significant number of leak repairs on their gas distribution pipelines; operators are not discovering or repairing a significant number of leaks on their gas distribution pipelines; or existing regulatory requirements and operator repair practices have not yielded improvements in reducing the frequency of leak repairs (and perhaps have failed to yield improvements in leak identification) on gas distribution pipelines for nearly a decade. PHMSA incident report data for gas distribution pipelines shows that distribution system operators reported only 377 incident reports identified as leaks (rather than ruptures or mechanical punctures) during the entire period from 2010 through 2020. This represents a miniscule percentage of the 510,224 leak repairs reported on operators' annual reports in 2020 alone, a figure which does not include leaks that are not scheduled for repair at all. Forty-five percent of these reported leaks were attributable to causes that progressed over time (*e.g.,* corrosion failure, equipment failure, and material failure), which may have been discovered earlier through more frequent leakage surveys, patrols, and repair practices. As described later in this section, evidence that leaks that are large in release volume or hazardous to public safety are not reliably detected or repaired is further supported by available state-

[139] *See, e.g.,* Wilkowski, ''Leak-Before-Break, What Does It Really Mean?'' 122 *Journal of Pressure Vessel Technology* 267 (Aug. 2000); Zhang, et al., ''Paper: Preventive Leak Detection for High Pressure Gas Transmission Networks,'' *AAAI 2017* (2017); *see also* GPTC Guide appendix G–192–11 table 3c, recommending that grade 3 leaks be re-evaluated within 15 months or during the next required leakage survey.

level information shows persistent backlogs of grade 3 leaks and research with advanced leak detection methods, which suggests that operators may not reliably detect releases with large volumes or that are hazardous to public safety.

Data from States employing the three-tiered GPTC Guide leak grading framework (discussed in section II.E.) for gas distribution pipeline facilities demonstrates that most leaks on distribution main and service pipelines that are identified by operators are not subject to PHMSA repair requirements as hazardous leaks, and can persist for extended periods before repair. By way of example, the 2020 Pipeline Safety Performance Measures Report from New York State reports that out of 19,683 leaks on main and service pipelines discovered by 11 natural gas local distribution companies in 2019, 7,403 (37.6%) were grade 1 leaks that approximate to ''hazardous leaks'' under PHMSA repair requirements in § 192.703(c), while an additional 5,468 (27.8%) were grade 2 leaks, and 5,768 (29.3%) were grade 3 leaks using New York State requirements similar to the GPTC Guide criteria.[140] New York State has adopted repair deadlines mirroring those in the GPTC Guide for grade 2 leaks (12 months or 6 months, depending on potential hazard, see 16 NYCRR 255.813–255.815). However, neither the GPTC Guide nor New York regulations (as of October 2022) require repair of grade 3 leaks, resulting in a backlog of almost 10,000 outstanding unrepaired leaks in 2020.[141] Each of these unrepaired leaks will continue to release methane (or other gases) to atmosphere until remediated, and each could increase in size between patrols or leakage surveys. Minority populations and other disadvantaged communities often bear the brunt of unrepaired leaks on those gas distribution systems.[142] The IM regulations at subpart P have proven insufficient to prevent leaks, as all the gas distribution pipelines, including those in the New York data described above, had been subject to DIMP regulations.

The number of leaks from gas transmission pipelines are also significant. A review of PHMSA incident data yields that over 500 (roughly 40%) of the 1,300 incidents reported by gas transmission operators between 2010 and 2020 involved hazardous leaks.[143] PHMSA's IM regulations at subpart O do not ensure that pipeline operators prevent such leaks. Of the over 500 leaks reported as incidents on gas transmission pipelines between 2010–2020, nearly a quarter of those incidents occurred on gas transmission pipelines subject to subpart O requirements. Further, incident reports on gas transmission pipelines show that many were either identified during leakage surveys or patrols or were attributed to causes that could have degraded over time. PHMSA therefore expects that more frequent patrols and leakage surveys and prompt remediation would result in earlier detection and potential avoidance of leak degradation that would lead to incidents.

Annual report data similarly suggests a large number of leaks on gas transmission pipelines and the potential value of enhanced leak detection and repair requirements for promptly identifying and remediating those leaks. In annual reports submitted between 2012–2021, operators of gas transmission pipelines reported repairing an average of 13,600 leaks repaired per year across the 302,000 miles of gas transmission pipelines nationwide. But part 191 requires annual reporting of only the number of leaks repaired—not all detected leaks (even hazardous leaks detected but not repaired). In addition, part 192 does not provide clear timelines for ''prompt'' repair of hazardous leaks, much less any timeline for other leaks. Even if unreported, non-hazardous leaks occurred on gas transmission pipelines at just a fraction of the average, per-mile rate of hazardous leak repairs noted in annual reports over the last decade, there would be a significant number of additional, unreported leaks on gas transmission pipelines each year. Those unreported leaks would generally not be subject to prescribed repair timelines under existing PHMSA regulations. Although some of those leaks could be identified and corrected in a timely manner pursuant to PHMSA's IM regulations at subpart O, the limited application of those requirements (only transmission pipelines in HCAs) and the significant discretion given to operators in designing and executing IM plans do not guarantee any such leaks would be identified and remediated promptly.

PHMSA similarly understands that its existing regulations tolerate the persistence of numerous leaks on part 192-regulated gas gathering pipelines. Data from incidents on Types A and B gas gathering pipelines across 2010–2020 yields an average, per-mile rate of incidents—83 incidents on 11,542 miles of pipeline (0.0072 incidents/mile)—nearly double that of gas transmission pipelines (0.00435 incidents/mile) over the same period. Further, leaks are a more frequent cause of incidents on Types A and B gas gathering pipelines than for gas transmission pipelines—operators attributed nearly 80% of the incidents reported on Types A and B gathering pipelines to leaks. And PHMSA understands from reviewing incident reports for Types A and B gathering pipelines that many of those incidents could have been avoided or mitigated by more timely detection and repair. Annual report data for Types A and B gathering pipelines tells a similar story. In 2020 annual reports, Types A and B gathering operators reported 1,574 hazardous leak repairs on 298,795 miles of onshore gas transmission pipelines (5.3 leaks per 1,000 miles) and 153 hazardous leak repairs on 11,542 miles of Type A and Type B regulated onshore gas gathering pipelines (13.3 leaks per 1,000 miles). If the number of hazardous leak repairs corresponds to the total number of hazardous leaks identified, Types A and B gathering pipelines would have an average, per-mile rate of hazardous leaks more than twice that of gas transmission pipelines. Similar to the discussion above regarding distribution and transmission lines, the annual report-derived values understate the total number of leaks on Types A and B gathering lines. Therefore, the total number of leaks on Types A and B gathering lines not subject to any meaningful Federal repair requirements is likely even higher. Furthermore, the number and persistence of leaks on Type C pipelines are likely to be higher than on Types A and B gas gathering pipelines because Type C gathering pipelines have historically avoided any meaningful

[140] State of New York Department of Public Service, Case 21–G–0165, ''2020 Pipeline Safety Performance Measures Report'' (June 17, 2021), *https://www3.dps.ny.gov/W/PSCWeb.nsf/All/9DBA66C148A1310985257B2600750639?OpenDocument.* Note that New York leak classification requirements use the term ''types'' rather than ''grades,'' however they are conceptually identical.

[141] State of New York Department of Public Service, Case 21–G–0165, ''2020 Pipeline Safety Performance Measures Report'' at Appendix K (June 17, 2021), *https://www3.dps.ny.gov/W/PSCWeb.nsf/All/9DBA66C148A1310985257B2600750639?OpenDocument.*

[142] Luna et al., ''An Environmental Justice Analysis of Distribution-Level Natural Gas Leaks in Massachusetts, USA,'' 162 *Energy Policy* 112778 (2022). This study of the distribution of gas leaks reported to the Massachusetts Department of Public Utilities found consistently higher densities of unrepaired leaks in the homes of people of color, lower income persons, renters, adults with lower levels of education, and limited English-speaking households. These same groups were more likely to experience slower repair times and significantly older unrepaired leaks.

[143] This calculation is based on a review of gas transmission pipeline incident reports, excluding incidents attributed to other causes such as ''mechanical puncture,'' ''rupture'' or ''other.''

State or Federal reporting or design requirements.[144]

The number and persistence of leaks on gas distribution, transmission, and gathering pipelines tolerated by PHMSA regulations entail considerable risks to public safety.[145] Each of those leaks discussed above that were or became incidents reported pursuant to part 191 involved significant public safety consequences: specifically, one or more of death, personal injury necessitating in-patient hospitalization, property damage of $122,000 or more (excluding the value of the gas itself), or 3 MMCF or more gas lost. Similarly, each of the hazardous leaks observed on gas pipelines under existing PHMSA regulations are a hazard with respect to public safety. Since leaks in pressurized systems can over time degrade into catastrophic failures, even those leaks that have not yet been reported as incidents or otherwise designated as hazardous in that they do not involve an existing or imminent risk of ignition can nevertheless give rise to such risk if not repaired.

Lastly, any leak from gas gathering pipelines entails unique public safety risks. Natural gas gathering pipelines are often located in the vicinity of socially vulnerable populations.[146] Additionally, unprocessed natural gas within gathering pipelines typically contains significant quantities of volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) such as benzene (a known carcinogen). As discussed in further detail in the Preliminary RIA, VOCs and HAPs pose risks from long-term adverse health effects. VOC emissions are precursors to ozone, and to a lesser extent fine particulate matter ($PM_{2.5}$). Both ambient ozone and $PM_{2.5}$ are associated with adverse health effects, including respiratory morbidity, such as asthma attacks, hospital and emergency department visits, lost school days, and premature respiratory mortality. HAPs contained in unprocessed natural gas includes several substances that are known or suspected carcinogens, including but not limited to benzene, formaldehyde, toluene, xylenes, and ethylbenzene. Benzene and formaldehyde are known human carcinogens, and ethylbenzene has been identified as possibly carcinogenic in humans. Chronic (long-term) inhalation of benzene can result in several adverse noncancer health effects including arrested development of blood cells, anemia, leukopenia, thrombocytopenia, and aplastic anemia, and acute (short-term) exposure to benzene vapors has been reported to cause negative respiratory effects. Formaldehyde inhalation exposure also causes a range of noncancer health effects including irritation of the nose, eyes, and throat, and repeated exposures cause respiratory tract irritation, chronic bronchitis, and nasal epithelial lesions. There is evidence that formaldehyde may also increase the risk of asthma and chronic bronchitis in children. Inhalation of toluene, mixed xylenes, and ethylbenzene can have neurological, respiratory, and gastrointestinal effects, among others, with chronic exposure to toluene potentially leading to developmental effects such as central nervous system dysfunction, attention deficits, and other anomalies. Further, corrosives entrained in the unprocessed natural gas can accelerate corrosion in the vicinity of leaks, thereby increasing the risk of a catastrophic failure. Recent incident data on Types A and B gas gathering pipelines similarly underscores the unique risks to public safety posed by the exemption of any part 192-regulated gas gathering pipelines from PHMSA's NPMS reporting requirements. The average, per-mile rate of incidents due to excavation damage reported to PHMSA between 2010 and 2020 on Types A and B gathering pipelines was comparable to that on distribution pipelines (0.023 and 0.027 annual incidents per 1,000 miles, respectively); further, insufficient locating practices have been reported to PHMSA as a contributing factor in those incidents.

Aside from the public safety risks discussed above, leaks from gas distribution, transmission, and gathering pipelines are also a significant contributor to climate change. As discussed in section II.C.2 of this NPRM, current methane emissions data identifies leaks across line pipe alone on U.S. natural gas distribution, transmission, and gathering as a significant contributor (the GHGI estimates nearly 328.9 kt CH_4 in 2019) to U.S. methane emissions. But current methane emissions estimates could materially understate actual methane emissions. GHGRP reporting requirements do not capture all gas pipeline mileage subject to PHMSA's regulations at parts 191 and 192, introducing uncertainty into whether national average methane emissions estimates derived from such reports may accurately be extrapolated to all PHMSA-regulated gas pipelines. Additionally, recent evidence from aerial surveys of a small (7,500 square kilometer) swath of the Permian basin[147] found leaks from natural gas gathering pipelines in the Permian basin to be a larger source of methane emissions than would be calculated using the national average in the GHGI.[148] A series of two-week aerial surveys conducted in the fall of 2019, summer of 2021, and fall of 2021 conducted for the Environmental Defense Fund (EDF)'s Permian Methane Analysis Project observed between 50 and 350 leaks attributed to gas gathering line pipe, of which roughly half are likely attributable to part 192-regulated gathering line pipe. PHMSA made this assessment by comparing the leak coordinates for gathering line pipe within the raw data of EDF's Permian Methane Analysis Project[149] to geospatial data for specific gathering pipelines downloaded from the Texas Railroad Commission (TRRC) website.[150] PHMSA then reviewed the TRRC's database of attributes of those gathering pipelines to determine diameter, using that metric to determine whether an observed leak was on a part-192 regulated gathering pipeline. The leaks identified in these aerial surveys, moreover, were not de minimis: the average leak rate observed by EDF was 273 kg CH_4/hour, correlating to roughly a metric ton of methane emitted to atmosphere every five days. Even this limited Permian Basin data could under-report the number and scale of leaks from methane emissions from gas gathering pipelines if projected

[144] *See, e.g.,* PHMSA, Doc. No. PHMSA–2011–0023–0504, ''Response to Petition for Reconsideration of the Gas Gathering Final Rule'' at 3 (Apr. 1, 2022).

[145] PHMSA discusses in this section only direct public safety consequences of leaks; however (as explained in section II.D.3), leaks and other releases from gas pipelines can also have second-order public safety impacts resulting from climate change-induced natural force damage and equipment malfunction.

[146] Emanuel et al., ''Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States,'' 5 *GeoHealth* (June 2021) (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).

[147] The entire Permian basin covers approximately 86,000 square miles—more than 220,000 square kilometers.

[148] *See* Yu et al., ''Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin,'' Environ. Sci. Technol. Lett. (Nov. 8, 2022) (Yu Study) (''The EF [(emissions factor)] derived from each of the four aerial surveys is more than an order of magnitude higher than the EPA's published values [for national average emissions].''). The emissions factors calculated from this study were also ''4–13 times higher than the highest estimate derived from a published ground-based survey of gathering lines.''

[149] *See* EDF, Permian Methane Analysis Project, *https://permianmap.org/* (last accessed July 20, 2022).

[150] *https://rrc.texas.gov/oil-and-gas/publications-and-notices/maps/* (last accessed July 25, 2022).

nationwide.[151] Many of the gathering pipelines in the Permian basin are relatively new pipelines, while older gas gathering infrastructure in other production regions may leak at higher rates.

4. Regulatory Requirements Lag Commercially Available, Advanced Leak Detection Technologies

As explained above in section D.1, PHMSA regulations prescribe requirements for identifying leaks—leakage surveys and rights of way patrols—directed principally toward risks to public safety (from ignition of instantaneous, large-volume releases or accumulated gas) and not toward environmental harm that even small leaks can cause. Consistent with that historical approach, PHMSA regulations permit reliance on non-instrumented leak detection methods such as smell or visual surveys of gas transmission pipeline infrastructure and rights of way that are more appropriate for discovering ruptures or accumulated gas than smaller leaks. When leak detection equipment is required, PHMSA regulations specify neither particular leak detection technologies nor minimum performance standards for detection of gas concentration by leak detection equipment.

These shortcomings in PHMSA's regulatory regime allow operators to rely on inadequate or ineffective leak detection equipment and practices, rather than encouraging use of commercially available, advanced leak detection technologies and practices appropriate to different gases transported by gas pipeline facility subject to part 192. Many of these technologies and practices were discussed by PHMSA, industry and academic research organizations, and vendors within a virtual public meeting on advanced methane leak detection technology and practices hosted by PHMSA on May 5–6, 2021 (2021 Public Meeting).[152] PHMSA staff also attended the Methane Detection Technology Workshop hosted by EPA on August 23–24, 2021 (2021 EPA Methane Detection Technology Workshop).[153] [154] [155] [156] Presenters at these meetings described how innovations in equipment sensitivity, analytics, automation, and survey speed of leak detection services could increase the effectiveness and decrease the cost of detecting gas releases from oil and gas facilities.

At the 2021 Public Meeting, EDF presented a set of recommended elements for an advanced methane leak detection system, including (1) leak detection equipment with a parts-per-billion level of sensitivity [157] and the ability to capture other data for use in an algorithm to understand the size and location of leaks; (2) a defined deployment strategy or work practice to ensure that accurate data is being collected; and (3) comprehensive data collection on topics such as leak location, estimated leak flow rate or gas emission rate, a coverage map showing which areas were successfully surveyed and which areas were not, and a summary or cumulative loss estimate for the total area surveyed. AGA observed in their remarks at the 2021 Public Meeting and AGA et al.[158] in their written comments that most currently available leak detection technologies are focused on identifying indications of methane leaks in the air (*i.e.,* gas concentration) rather than measuring the rate of leakage from a component. AGA et al. characterized methane concentration as a more appropriate metric for evaluating the public safety risks from explosion than for estimating the amount of methane going to atmosphere.

Several stakeholders at the 2021 Public Meeting emphasized the importance of flexibility in PHMSA's consideration of advanced leak detection standards, recommending that PHMSA assess the suite of leak detection technologies that are currently commercially available and introduce requirements that promote continued development of advanced technologies. EDF noted that it was essential that PHMSA set advanced methane leak detection standards that ensure an ongoing process for continuous technology improvement, recommending that PHMSA set a floor, not a ceiling, to create a space in Federal standards to push for the development of new ideas and improvements to technology over time for future incorporation. AGA et al. also suggested that applying prescriptive regulations could potentially limit the development of different technologies and innovations, stating that providing operators with flexibility can create opportunities and incentives for developing new technologies and innovations in leak detection and measurement. Similarly, the Pipeline Safety Trust (PST) stated that performance-based regulations for advanced leak detection (ALD) and methane reduction should use the capabilities of commercially available ALD technologies as a starting point, but that the ALD performance standards should change as commercially available technologies develop.

AGA et al. emphasized the value of leak data analysis in lieu of requirements that operators use specific advanced leak detection technologies. AGA et al. observed that studies across the gas industry supply chain show that a majority of emissions come from a small number of high-emitting leaks, and thus leak data analysis enables operators to make substantial inroads on reducing methane emission by identifying and prioritizing repair of the highest-emitting leaks. AGA et al. also urged PHMSA to consider the affordability of any new regulatory requirements and suggested that in some situations, a simpler, less costly technology or practice may achieve safety and environmental goals more successfully than a newer technology.

Notable commercially available, advanced leak detection technologies

[151] The Yu Study acknowledged that its data may also be underestimating emissions from gathering pipelines. The authors conservatively excluded any emissions sources in areas of co-located gathering and transmission pipelines where the source could not be definitively attributed, although the authors noted that it would be reasonable to assume at least some of those sources were from gathering pipelines. *See* Yu et al.

[152] Recordings, transcripts, and slides from the 2021 Public Meeting are available at the meeting web page at *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=152.* A number of entities submitted written comments before and after the meeting that are available in the rulemaking docket at Doc. No. PHMSA–2021–0039.

[153] Recordings are available at the EPA meeting web page at: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop#:~:text=Natural%20Gas%20Industry-,EPA%20Methane%20Detection%20Technology%20Workshop%20%2D%2D%20August%2023%20and%2024,oil%20and%20natural%20gas%20industry* (last accessed July 20, 2022).

[154] See ''Attachment 1: Summary Report Methane Detection Technology Workshop'' of ''Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG)'' at *https://www.regulations.gov/* Docket ID No. EPA–HQ–OAR–2021–0317–0166.

[155] See ''EPA's Methane Detection Technology Virtual Workshop. August 23–24, 2021. Audio'', ''Transcripts'', and ''Presentations'' at *https://www.regulations.gov/* Docket ID No. EPA–HQ–OAR–2021–0317–0183, EPA–HQ–OAR–2021–0317–0181, and EPA–HQ–OAR–2021–0317–0182 respectively.

[156] See ''Controlling Air Pollution from the Oil and Natural Gas industry. EPA Methane Detection Technology Workshop. August 23 and 24, 2021'' *https://www.regulations.gov/* Docket ID No. EPA–HQ–OAR–2021–0317–0183.

[157] EDF commented that parts-per-billion detection is important in this effort in light of the potential for hidden underground leaks, where only a small volume of gas may migrate through the pavement despite a significant leak buried under the street.

[158] The American Gas Association (AGA), API, American Public Gas Association, GPA Midstream Association (GPA), and Interstate Natural Gas Association of America submitted joint comments (Doc. No. PHMSA–2021–0039–0008) to the rulemaking docket after the 2021 Public Meeting. Throughout this NPRM, references to ''AGA et al.'' refer to those joint comments.

and practices [159] are described briefly below.

Hand-Held Leak Detection Equipment

The most common method for instrumented leakage surveys (meaning a leakage survey performed using leak detection equipment) on natural gas pipelines consists of surveys along the pipeline right-of-way with handheld leak detection equipment. A surveyor typically uses a flame ionization detector (FID), infrared gas detector, optical gas imaging (OGI) device,) or other gas detector to sample gas above a buried pipeline, inside underground structures, and possibly in the soil. Handheld equipment is used to perform most leakage surveys, and any advanced leak detection solution that does not operate directly on or over the pipeline would still require confirmation of leak indications on the ground by operator personnel with handheld equipment. For aboveground or excavated leaks, gas detection instruments are often supplemented with a ''soap test'' that involves applying a soapy solution to the probable leak location. The location and size of the bubbles produced by escaping gas provides an indication of the exact location of the leak source and the relative size of the leak.

Handheld devices have been a focus of research and development (R&D) by PHMSA, equipment manufacturers, and operators. Recent innovations available on the market, including highly sensitive handheld equipment and laser-based detectors capable of detecting gas at a distance, have improved the effectiveness, efficiency, and safety of traditional walking surveys. A walking survey can be effective at detecting pipeline leaks, assuming that the location of the pipeline is known, adequate equipment is used, and survey personnel follow procedures that ensure the pipeline and potential migration paths are properly surveyed, and there may not be an alternative to walking surveys in some environments with poor equipment access. The performance of leak detection equipment and procedures may vary depending on weather and soil conditions or other environmental factors. The GPTC Guide includes guidelines for performing leakage surveys.

Walking surveys, however, tend to be expensive and time-consuming because they require significant personnel resources to execute. Effectiveness of even advanced handheld leak detection technologies can be reduced by poor operator training, inadequate survey procedures, or use of poorly maintained or uncalibrated equipment.

Automobile-Based Leak Detection Equipment

Similar equipment used in walking surveys can be mounted on cars and trucks to allow efficient surveying of pipelines with adequate road access. The effectiveness of a mobile survey depends on weather conditions, the survey procedure, and whether the equipment has acceptable access to the location of the pipeline and possible gas migration paths. Some vendors have taken this concept a step further and combined highly sensitive gas detectors, some capable of detecting gas in the single ppb range, anemometers, GPS sensors, other sensors, and advanced analytics to enhance the capabilities of vehicle-based leakage surveys. Some advanced vehicle-based leak detection systems typically function by combining gas readings and wind indications to estimate the size and point of origin of a plume of gas as the vehicle drives through it. These leak indications (and gaps in the survey coverage) are then assessed by personnel with handheld equipment. For example, two studies measured gas concentrations in Boston, MA, and Washington, DC using Picarro mobile methane analyzer technology. In the 2004 survey of Washington, DC, the researchers surveyed 1500 miles of streets using a Picarro G2301 spectrometer device and the Picarro A0491 Mobile Plume Mapping Kit (A combination of the gas analyzer, a GPS device, and an anemometer). According to the equipment manufacturer, the G2301 device has sub 0.5 ppb precision over 5 seconds and an operating range of 0–20ppm when measuring methane,[160] though testing of the device during the Boston study found analyzer output to be within 2.7 ppb of known gas concentration during testing.[161] In Washington, DC, out of 5,893 methane readings detected from the vehicle with a concentration greater than 2.5 ppm, the minimum concentration defined as a leak indication in the study, 1,112 were measured at 5 ppm or greater.[162] Additionally, the researchers inspected 19 of the larger emissions sources with a handheld combustible gas indicator and found gas concentration in nearby manholes exceeding 80% LEL (*i.e.,* a grade 1 hazardous leak) at 12 locations. Upon notifying the distribution operator, a subsequent reinspection found that hazardous conditions remained at nine leak locations. In Boston, 435 out of 3,356 methane indications were measured at 5 ppm or greater.[163] However, these measurements are based on ''in-plume'' measurements consistent with the operation of the Picarro mobile methane analyzer and similar vehicle-based systems rather than direct measurements within 5 inches of the leak location. The concentration of each potential leak indication measured in-plume is likely to be lower than the concentration measured in the immediate vicinity of the emissions source during a leak investigation.

Advanced vehicle-based leak detection systems were discussed extensively during the 2021 Public Meeting. A number of technology providers market automobile-based leak detection systems. EDF discussed their experience with advanced vehicle-based leak detection systems in partnership with Google and Pacific Gas and Electric (PG&E). According to EDF, research indicates that advanced mobile leak detection systems, vehicle-based platforms that rely on sensitive gas detectors, anemometers, GPS devices, other sensors, and analytics to locate the approximate source of gas plumes indicating possible leaks, can find more leaks in distribution systems compared to traditional survey methods. Also, according to EDF, one study found that surveys conducted by ''traditional'' methods in two cities failed to find 65 percent of the leaks that were discovered by advanced leak detection technologies, including some grade 1 leaks. EDF further commented that quantifying emissions can allow operators to prioritize replacement programs more effectively to the largest individual leaks.

On the other hand, AGA noted issues with excessive ''false positives'' from mobile survey technologies, where there are indications of leaks where none exist. AGA also noted that mobile survey technologies can fail to detect

[159] PHMSA acknowledges that much of the discussion of advanced leak detection technologies and practices in this section is presented in terms of advanced methane leak detection technologies for use in connection with natural gas pipeline facilities, rather than leak detection technologies and practices for other gases whose transportation within pipeline facilities is subject to part 192. However, many of the advanced leak detection technologies and practices for methane are comparable to the technologies and practices employed in connection with other gases.

[160] Picarro. G2301 Gas Concentration Analyzer Datasheet, *https://www.picarro.com/g2301_gas_concentration_analyzer* (last accessed Dec. 20, 2022).

[161] Phillips et al., ''Mapping Urban Pipeline Leaks: Methane Leaks Across Boston,'' 173 *Environmental Pollution* at 1–4 (2013).

[162] Jackson et al., ''Natural Gas Pipeline Leaks Across Washington, DC,'' 48 *Environmental Science & Technology* at 2051–2058 (2014).

[163] Phillips et al., ''Mapping Urban Pipeline Leaks: Methane Leaks Across Boston,'' 173 *Environmental Pollution* at 1–4 (2013).

indications of a leak when a leak does exist. False positives require confirmation by operator personnel, and therefore cut into the cost-effectiveness of such surveys. PHMSA, during the 2021 Public Meeting, noted that there are challenges with certain leak detection technologies depending on the area where the survey is being performed.[164] For instance, driving surveys might best be conducted in densely populated areas where pipelines follow roadways. However, in rural areas with gas transmission and gathering pipelines, it can be more effective to use aerial surveys or continuous monitoring technology because pipeline rights-of-ways may be difficult to traverse on the ground. There might also be issues for operators using laser-based and other line-of-sight equipment in some areas.

Aerial Sensors and Continuous Monitoring

Other areas of industry interest are aerial sensing platforms and continuous monitoring. Aerial sensing involves gas detection equipment mounted on fixed wing or rotary wing aircraft, unmanned aerial systems (UAS), or satellites. Many aerial sensing methods are similar in principle to those used in advanced vehicle-based leak detection systems, except that the sensor suite is mounted on an aircraft or UAS, instead of a car or truck. Other aerial platforms may use direct sampling, laser-based methane detectors, LIDAR, OGI, or other methods that detect methane gas concentrations along a pipeline right-of-way or at aboveground facilities.

Recent research and perspectives shared at the August 2021 EPA technology workshop described above illustrate the potential advantages of aerial survey technologies for certain oil and gas facilities. The primary advantage of aerial surveys is that the speed of an aircraft can allow more efficient or more frequent surveys of large areas. Depending on the configuration of the facility, aerial surveys are potentially highly cost-effective. For example, during a panel conversation on the first day of the 2021 EPA Methane Detection Technology Workshop, Triple Crown Resources reported cost-effective methane emissions reductions of up to 90% from upstream production facilities via aerial surveys performed by Kairos Aerospace.[165] In addition to leak detection and repair procedures, the operator also made changes to its operations and maintenance procedures to address the minimization of releases from tanks and other equipment. In that same panel, another operator reported that aerial surveys were not cost-effective for all of their facilities, but that aerial surveys, especially those mounted on UAS, have the additional advantage of being able to maneuver around locations or facilities that may be difficult for operator personnel to safely access with traditional equipment.[166] On the second day of the 2021 EPA Methane Detection Technology Workshop, a representative of BPX Energy (British Petroleum's onshore U.S. production business) described the company's quarterly aerial survey program using fixed wing aircraft and UAS in the Permian Basin, which is designed to detect, image, quantify, and map methane sources with an emissions rate greater than 5.5 mcf/d.[167] BPX reported that the aerial surveys can cover over 100 square miles per day, although these surveys are susceptible to meteorological conditions. The advantages of aerial surveys are likely to be most significant on long-distance transmission lines that can be surveyed efficiently with fixed wing aircraft. Likewise, long-distance or dense gas gathering pipeline networks may also be cost-effective to survey by air.

In contrast, drawbacks and limitations of aerial and continuous monitoring are similar to those of motor vehicle-based systems. While aircraft can access facilities that may be difficult to access with ground-based vehicles, the speed and altitude required for operation of fixed wing aircraft and helicopters can reduce the reliability of detecting smaller releases since gas concentration decreases with distance from the source and increased speed decreases the likelihood that an accurate measurement will be taken as the vehicle intersects a gas plume. Additionally, aerial surveys may not be cost-effective for some system configurations. Most research and application of aerial systems have been in the upstream sector on gas production, processing, and gathering systems.

PHMSA expects that use of UAS for aerial monitoring will grow as technology continues to advance, and the Federal Aviation Administration (FAA) continues its work to integrate UAS into the National Airspace System. On January 15, 2021, FAA published a final rule to permit the operation of UAS at night and over people under certain conditions.[168] FAA is currently considering recommendations from an Aviation Rulemaking Committee on a regulatory approach to support beyond visual line of sight operations in the National Airspace System.[169]

Continuous monitoring can take many forms and is a fast-maturing area of development. The most straightforward means of providing continuous monitoring is with stationary gas detectors that are able to communicate with operator personnel or a control center. The most straightforward means of continuous monitoring is mounting stationary sensors such as gas samplers or laser-based detectors in the vicinity of a pipeline. A stationary gas sampler must be located near potential leak locations in order to detect leaks, laser-based systems must have potential leak sources or migration paths within the line of sight and effective range of the device, though some newer devices are capable of scanning. Continuous monitoring with such sensors can therefore be costly, since more devices are required versus using one device to perform a survey, however real time leak information is a significant advantage, especially for intermittent sources. For example, the BPX Energy presentation at the 2021 EPA Methane Detection Technology Workshop noted that the company's stationary sensors refresh every 15 minutes.[170] For this reason, continuous monitoring can be especially effective at aboveground facilities where probable fugitive emissions sources are known

[164] Similarly, GPA and API submitted joint comments (Doc. No. PHMSA–2021–0039–0004) following the 2021 Public Meeting stating that the differences between gas gathering pipelines and gas transmission and distribution pipelines should be considered in developing any new regulations, guidance documents, or enforcement policies related to leak detection and repair.

[165] Johnson, Forrest and Wlazlo, Andrew. ''Airborne Methane Surveys Pay for Themselves: An Economic Case Study of Increased Revenue from Emissions Control'' Triple Crown Resources. EPA Methane Detection Technology Workshop (August 23, 2021). *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop.* Day 1 at 2:32:15.

[166] Bernica, P.E., ''Key Takeaways from Deploying Four Novel Methane Detection Technologies''.

[167] Faye Gerard, Ph.D. ''BPX, Methane Measurements.'' BP America. EPA Methane Detection Technology Workshop (August 24, 2021). *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop.* Day 2 at 2:39:10.

[168] FAA, ''Operation of Small Unmanned Aircraft Systems Over People,'' 86 FR 4314 (Jan. 15, 2021).

[169] Unmanned Aircraft Systems Beyond Visual Line Of Sight Aviation Rulemaking Committee Final Report, March 2022, available at *https://www.faa.gov/regulations_policies/rulemaking/committees/documents/media/UAS_BVLOS_ARC_FINAL_REPORT_03102022.pdf.*

[170] Faye Gerard, Ph.D. ''BPX, Methane Measurements.'' BP America. EPA Methane Detection Technology Workshop (August 24, 2021). *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop.* Day 2 at 2:48248.

beforehand and at high-risk locations where real-time alarms can help ensure public safety from fire and explosion risk.

Vendors and operators have been experimenting with a number of methods such as pressure wave monitoring, acoustic monitoring, in-ditch sensing with fiber optic sensors, and other devices. At the May 2021 Public Meeting, Siemens Energy and ProFlex Technologies presented on a negative pressure wave sensing technology for detecting ''spontaneous leaks'' on gas transmission, gas gathering, and similar applications. In that technology, pressure sensors placed periodically along the pipeline can detect anomalous negative pressure waves that propagate from the location of a rupture. According to the technology provider, the system can detect, by timing the rupture indications on the upstream and downstream sensors, estimate the location of the rupture within 20–50 linear feet. The technology provider claims that the system can detect leaks between ½ inch to 2 inches in area within a few seconds, therefore is potentially a sensitive and reliable means of detecting pipeline ruptures, however the system may not be able to reliably detect smaller leaks.[171]

In-Residence Methane Detection Tools

Another emerging area of industry interest is in-home methane detection. While gas piping downstream from the outlet of a customer meter is not regulated under the Federal pipeline safety regulations, PHMSA encourages the adoption of in-home methane detectors by operators, States, and standards developing organizations. As a result of NTSB investigations into a series of gas-related incidents in a neighborhood in Dallas, Texas in late February of 2018,[172] and an investigation into an apartment explosion in Silver Spring, MD,[173] the NTSB included in-home methane detection on its 2021–2022 NTSB Most Wanted List.[174] NTSB recommended that the International Code Council, the National Fire Protection Association, and the Gas Technology Institute (GTI) cooperate to develop standards and incorporate provisions in applicable national codes to require methane detection systems for all types of residential occupancies with gas service. The NTSB recommended that, at a minimum, these requirements should cover the installation, maintenance, placement of the detectors, and testing requirements. The PST and other public safety advocacy groups have also called on operators to install this technology wherever possible to provide for better public and environmental safety, as this technology can provide an extra level of protection against dangerous leaks. At the 2021 Public Meeting, the PST stated that the increased usage of in-home methane detectors would be relatively inexpensive and have the potential to dramatically reduce injuries, property damage, and deaths resulting from leaks and explosions from gas distribution systems.

Integration of Advanced Technologies and Practices Within Advanced Leak Detection Programs

Each of the commercially available, advanced technologies described above have inherent limitations that make their use more or less appropriate for use in connection with different gases, pipeline facilities, operating environments, weather conditions, and other factors. And even state-of-the-art equipment can deliver poor results if the operator's procedures or training are inadequate or if equipment malfunctions. For this reason, a number of speakers during the 2021 Public Meeting emphasized that ALDPs must consist of a portfolio of mutually reinforcing advanced leak detection technologies, practices, and policies, each providing defense-in-depth for the inherent or operational limitations of other program elements.

An incident that occurred on a gas distribution pipeline operated by Atmos Energy, in Dallas, Texas on February 23, 2018, that had been surveyed shortly before the incident illustrates this truism.[175] Prior the February 23 incident, two other gas-related fires occurred on the same block on February 21 and February 22. The NTSB concluded that it is likely that the three incidents are related, but fire department investigators and operator personnel failed to pinpoint the source of the leak that led to the February 23 incident. Since the fire department and the operator had not identified the distribution pipeline as the cause of the first two fires, no incident was reported to PHMSA. Following the February 22 fire, Atmos performed a leakage survey and repaired high-priority leaks on the pipeline segment involved in the incident. Atmos Energy's leakage surveys incorporated modern leak detection equipment such as FIDs, optical methane detectors, remote methane leak detectors (RMLD, a type of laser-based gas detector), and other devices. However, the manufacturer's instructions for the RMLD devices used to perform the leakage survey noted that the device performs sub-optimally in wet conditions and is not to be used when sustained wind or gusts exceed 15 mph. Additionally, the operator's combustible gas indicator could be damaged when saturated. Due to precipitation, wind, and wet soil conditions, the operator's RMLD survey was ineffective and the operator's barhole[176] procedures to measure gas concentrations in the soil could not be performed. As a result, the operator failed to detect leaking gas from a cracked main, resulting in a third, fatal explosion on February 23, 2018.

5. State-Level and Operator Leak Detection and Repair Requirements

PHMSA regulations, as explained in section II.D.1 above, require operators of part 192-regulated gas transmission and distribution pipelines and certain regulated gathering pipelines to repair hazardous leaks promptly—without providing meaningful guidance regarding which leaks are hazardous, or precisely when any leaks must be repaired. The limitations of regulatory initiatives undertaken by State authorities and voluntary efforts (including methane emissions reduction commitments and pertinent industry standards) by pipeline operators, moreover, underscore the need for robust Federal leak detection, grading, and repair requirements.

GPTC Guide

The GPTC is an ANSI-accredited committee (ANSI Z380, or the Committee) that was formed in the late 1960s under the American Society of Mechanical Engineers. The Committee operates under a consensus process and is technically based and independent. The Committee is composed of

[171] ProFlex Technologies and Siemens. ''Siemens Energy Spontaneous Leak Detection Service powered by ProFlex.'' May 2021. *https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1154.*

[172] NTSB, Pipeline Accident Report 21–01, ''Atmos Energy Corporation Natural Gas-Fueled Explosion; Dallas, Texas; February 23, 2018'' (Jan. 12, 2021).

[173] NTSB, Pipeline Accident Report 19–01, ''Building Explosion and Fire: Silver, Spring, Maryland: August 10, 2016'' (Apr 24, 2019).

[174] NTSB, ''Improve Pipeline Leak Detection and Mitigation: 2021–2022 Most Wanted List of Transportation Improvements'' (Apr. 6, 2021).

[175] NTSB, Pipeline Accident Report 21/01 ''Pipeline Accident Report: Atmos Energy Corporation Natural Gas-Fueled Explosion: Dallas, Texas: February 23, 2018'' (Jan. 12, 2021).

[176] A barhole is a small hole dug into the ground in order to measure the concentration of gas within the soil by taking a sample within the barhole with a probe.

approximately 100 members from all facets of the gas industry, including gas distribution, transmission, storage, and gathering operators and manufacturers of gas-related equipment. The Committee also has members from the regulatory community, including PHMSA, the National Transportation Safety Board (NTSB), and other Federal and State regulatory agencies. Approximately 40 of the Committee's members, including PHMSA, are voting members.

The Committee publishes the GPTC Guide as an implementation tool facilitating compliance by gas pipeline operators with PHMSA regulatory requirements.[177] The first edition of the GPTC Guide was published in 1970, around the same time the Federal Pipeline Safety Regulations were first promulgated. The GPTC Guide is under continuous review and may be updated when prompted by pending rulemakings, NTSB reports, and requests from stakeholders, including PHMSA, the National Association of Pipeline Safety Representatives (NAPSR), or members of the public. The Committee periodically reviews requests for updates and may create a task group, if necessary, to issue new or amended guidance of versions of the GPTC Guide. The current edition of the GPTC Guide is the 2022 edition (including Addendum 1), published in June 2022.

Like the Federal Pipeline Safety Regulations, the GPTC Guide's leak grading and repair criteria are focused primarily on public safety rather than environmental protection. While the GPTC Guide itself has not been incorporated by reference in the Federal Pipeline Safety Regulations, several States have adopted at least the tiered leak grading criteria of the GPTC Guide and associated repair requirements into their regulations governing gas pipelines,[178] and PHMSA has referenced it from time-to-time in its implementing guidance.[179]

Additionally, some gas pipeline operators incorporate sections of the GPTC Guide into their operating and maintenance procedural manuals for detecting, investigating, and classifying leaks.

The GPTC Guide contains appendices that provide procedures that comply with part 192. The GPTC Guide also provides guidance for controlling methane leaks from natural gas pipeline leaks in Appendix G–192–11 For gas distribution pipelines, section 6.2 of the DIMP guidance in Appendix G–192–8 describes possible elements of an "effective leak management program" and references the criteria for grading leaks from Appendix G–192–11 and, for liquefied petroleum gas (LPG) systems, Appendix G–192–11A. Each section includes tables 3a, 3b, and 3c summarizing the grading criteria and recommended repair requirements. The grading criteria from GPTC Guide Appendix G–192–11 and Appendix G–192–11A are discussed below (hereafter, references to the GPTC Guide refer specifically to Appendix G–192–11 and 11A unless otherwise specified).

Section 5.5 of the GPTC Guide characterizes a grade 1 leak as a "leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous." This mirrors the definition of a "hazardous leak" at § 192.1001. This characterization omits consideration of potential hazard to the environment, and the phrase "existing or probable hazard" is not defined in any part of the GPTC Guide. However, Table 3a of the GPTC Guide provides the following examples of grade 1 leaks:

(1) Any leak that, in the judgment of operating personnel at the scene, constitute an immediate hazard.

(2) Escaping gas that is ignited.

(3) Any indication of gas which has migrated into or under a building, or into a tunnel.

(4) Any indication of gas which has migrated to at an outside wall of a building where gas would likely migrate or into a tunnel.

(5) Any reading of 80% [of the lower explosive limit] LEL, or greater, in a confined space.[180]

(6) Any reading of 80% LEL, or greater, in small substructures (other than gas-associated substructures) from which gas would likely migrate to the outside wall of a building.

(7) Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property.

Building on the § 192.703(c) requirement that hazardous leaks (*i.e.,* grade 1 leaks) be repaired promptly, the GPTC Guide further specifies that an operator must take immediate and continuous action to protect life and property until the conditions are no longer hazardous. Per the GPTC Guide, such continuous actions could include: implementing an emergency plan written in accordance with § 192.615; evacuating the premises; blocking off an area; re-routing traffic; eliminating ignition sources; and venting the area by removing manhole covers, bar-holing, or installing vent holes. The GPTC Guide also notes that, for grade 1 leaks, operators should stop the flow of gas by closing valves or by other means and notify appropriate police and fire departments.

A grade 2 leak is an intermediate risk classification in the GPTC Guide. The GPTC Guide characterizes a grade 2 leak as a "leak that is non-hazardous at the time of detection but that requires or justifies a scheduled repair based on probable future hazard." Like the description of a grade 1 leak, the characterization of a grade 2 leak in the GPTC Guide does not address hazards to the environment and does not provide a definition for the term "probable future hazard," although example criteria are provided in Table 3b of the GPTC Guide. For grade 2 leaks, these criteria include leaks that require action ahead of the ground freezing, or where changes in venting conditions would likely cause gas to migrate to the outside wall of a building. Grade 2 leaks could also include leaks with a reading of 40% of the LEL or greater under a sidewalk in a wall-to-wall paved area that does not qualify as a grade 1 leak; a reading of 100% LEL or greater anywhere under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a grade 1 leak; a reading between 20% and 80% of the LEL in a confined space or in a small substructure; any non-zero concentration reading on a pipeline

[177] GPTC Guide at 18 ("While the GPTC Guide is intended principally to guide operators of natural gas pipelines, it is a valuable reference for operators of other pipelines covered by Part 192").

[178] *See* National Association of Pipeline Safety Representatives (NAPSR), *Compendium of State Pipeline Safety Requirements and Initiatives Providing Increased Public Safety Levels Compared to Code of Federal Regulations, Third Edition* (Feb. 2022) (Compendium). References to "NAPSR" or to pertinent State requirements in this NPRM will, unless otherwise noted, will be to information within the Compendium.

[179] *See, e.g.,* PHMSA, "Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators" (2013) at 2 (directing larger distribution pipeline operators to refer to GPTC guidelines); PHMSA, Interpretation Response Letter No. PI–93–009 (February 11, 1993) (recommending public stakeholder consult the GPTC Guide for further determination of instruments and techniques to be used in certain leak detection activities); *see also* PHMSA, Interpretation Response Letter No. PI–99–0105 (December 1, 1999) (stating that the GPTC Guide "is a document endorsed by us which contains information and some methods to assist the gas pipeline operator in complying with the regulations contained in 49 CFR part 192").

[180] The Lower Explosive Limit (LEL) is the lowest concentration of gas that will burn in air in the presence of an ignition source.

operating at 30% of SMYS or greater in a Class 3 or Class 4 location that does not qualify as a grade 1 leak; and finally, any leak that, in the judgment of the operating personnel at the scene, is of sufficient magnitude to justify or require a scheduled repair. These examples demonstrate that the grade 2 leak classification, like the grade 1 classification, focuses operators on hazards to persons and property, without consideration of impacts on our environment.

The GPTC Guide requires that, upon detecting a grade 2 leak, an operator should repair or clear the leak ''within one calendar year but no later than 15 months from the date the leak was reported.'' The GPTC Guide states that, in determining the repair priority for the leak, an operator should consider the extent of gas migration, the proximity of gas to buildings in sub-surface structures, and the soil conditions (including frost cap, moisture, or natural venting). Operators can take a range of actions in addressing grade 2 leaks under the GPTC Guide. Some grade 2 leaks that are evaluated by the criteria listed above may justify a scheduled repair within 5 working days, whereas others might justify repair within 30 days. The GPTC Guide suggests that operators should schedule some grade 2 leaks for repair on a ''normal routine basis,'' with periodic re-inspection as necessary. The GPTC Guide suggests that operators should reevaluate grade 2 leaks at least once every 6 months until they are cleared, establishing a frequency of reevaluation based on the location and magnitude of the leak.

The GPTC Guide characterizes a grade 3 leak as ''a leak that is non-hazardous at the time of detection and can reasonably be expected to remain non-hazardous.'' The term ''non-hazardous'' is not itself defined, but comparison to the grade 1 and grade 2 descriptions indicates that the grade 3 classification is intended to be a catch-all classification for all leaks that do not constitute either grade 1 or grade 2 leaks, including those leaks that are hazardous to the environment without representing a potential risk to public safety. Based on the criteria in Table 3c, grade 3 leaks would include leaks where there is a reading of less than 80% LEL in a small gas-associated substructure, any reading under a street in areas without wall-to-wall paving where it is unlikely that gas could migrate to the outside wall of a building, and any reading of less than 20% LEL in a confined space. The GPTC Guide suggests that operators should reevaluate grade 3 leaks during their next scheduled survey, or within 15 months of the date the leak is reported, whichever comes first, and continue reevaluations until the leak is either regraded or is no longer leaking. The GPTC Guide does not require the repair of grade 3 leaks. In comments submitted following the 2021 Public Meeting, AGA et al. noted the limitations of the GPTC Guide leak grading system with respect to environmental safety in light of the GPTC Guide's focus on repair and remediation of leaks that are hazardous to public safety only.

The GPTC Guide provides for re-grading of existing leaks based on changes identified during subsequent evaluations. If an operator discovers, during a reevaluation, that a grade 2 or 3 leak has become worse following its initial detection and grading to the point where it would now be classified at a higher grade, an operator must upgrade the leak to its appropriate grade and take appropriate action in accordance with the new grade. The GPTC Guide also permits operators to downgrade leaks by making temporary repairs to make the leak less hazardous. For example, an operator may vent a grade 1 leak by drilling multiple barholes into the soil in the immediate vicinity of the leak or by leaving vault boxes open to the atmosphere before grading the leak. These techniques can ensure that a leak is not an immediate hazard to persons or property and justify downgrading the leak to a grade 2 leak.

As described in section II.D.1, existing regulations require repair of hazardous leaks. In practice, the term hazardous leak has corresponded to a grade 1 leak under the three-grade leak classification framework in the GPTC Guide; a grade 1 leak is the most urgent classification under this framework. Section 5.5 of appendix G–192–11 of the GPTC Guide characterizes a grade 1 leak as one that ''represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.'' However, PHMSA regulations do not currently require the repair of leaks other than hazardous leaks that would be classified as grade 2 or grade 3 based on the GPTC Guide. Regarding the replacement or remediation of pipelines known to leak, appendix G–192–18 of the GPTC Guide suggests operators consider replacement of cast iron pipe based on the maintenance and leak history and operational and environmental circumstances and provides guidance on factors and situations to consider.

State Leak Detection, Repair, and Reporting Requirements

State regulatory requirements impose a patchwork of obligations on pipeline operators with respect to leak detection and repair. Pertinent requirements vary from one State to the next and even within a single State based on the type (gathering, transmission, or distribution) of pipeline in question or the gas being transported. Many of those State requirements are (like PHMSA's current regulations) directed toward addressing imminent public safety risks rather than the climate and potential future safety risks posed by gas pipeline leaks. And, according to NAPSR data, only a minority of the States have leak detection and repair regulations that exceed the current minimum Federal regulations for any type of gas pipeline.[181]

A handful of States require more frequent leakage surveys than required by part 192. Many of those survey requirements apply to only certain types of pipelines, with more demanding requirements for distribution systems than for other types of gas pipelines (*e.g.,* gathering, intrastate transmission lines). And those requirements typically are directed toward addressing public safety rather than environmental harms, targeting areas where gas is likely to accumulate, where there is a high safety hazard in the case of a gas explosion, or pipelines that are higher risk due to their pressure or material. For example, the California Public Utility Commission requires annual leakage surveys ''in the vicinity of schools, hospitals and churches,'' in addition to the requirements for business districts in § 192.723, and requires that gas transmission pipelines be surveyed using leak detection equipment at least twice each year. Maryland requires annual leakage surveys for service pipelines serving places of public assembly. South Carolina requires leakage surveys for cathodically unprotected distribution pipelines at least once every 12 months, rather than 3 years as specified in § 192.723. Certain States also require operators to conduct more frequent surveys based on the location of the pipeline; for example, if the pipeline delivers gas to high-occupancy buildings or buildings of public assembly such as theaters, hospitals, or schools, or if the pipeline is near bridges or other transportation infrastructure. Other States provide a definition of the term ''business

[181] Zanter, Mary. ''Presentation of NAPSR at 2021 Public Meeting'' (May 5, 2021), *https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1150.*

district'' subject to more frequent leakage surveys in § 192.723 but not defined in part 192. While a small minority of States do have increased surveying of cast iron pipes under certain conditions, few States require operators to replace or remediate these or other types of leak-prone pipe materials.

A minority of States have more specific requirements for the use of leak detection equipment than contemplated by current PHMSA regulations. NAPSR's Compendium identified three States with leak detection equipment requirements that are more demanding than PHMSA's requirements. Those States' requirements seem largely focused on methane leaks from natural gas pipelines rather than leaks from pipeline facilities transporting other gases. A handful of states specify allowable leak detection equipment, generally requiring the use of an FID or equivalent device. For example, Maryland regulations require the use of flame ionization, combustible gas indicator in a barhole, optical methane detector, or other method approved by the Maryland Public Service Commission. New Jersey adopted an energy-related master plan in their overall State-wide climate goals that specifically directs the State utility commission to establish a standard for the use of advanced leak detection technologies when performing leakage surveys. NAPSR data indicates, however, that a majority of States do not have any more demanding requirements than PHMSA for the leak detection equipment used by operators. NAPSR's Compendium similarly indicates that few States have right-of-way patrol requirements for gas gathering or transmission pipelines more demanding than those in current PHMSA regulations.

Most States, moreover, do not have reporting requirements for leaks that are more demanding than those in current PHMSA regulations. NAPSR's Compendium indicates only a handful of States require periodic submission of leak status reports for any type of pipeline to State regulators, with a few States having recently adopted more comprehensive leak reporting requirements to achieve methane emission reduction goals. For example, California has established a comprehensive reporting system for gas utilities to submit annual methane leak abatement reports and compile emission reduction plans.

Apart from leak detection requirements, NAPSR's Compendium yields that a majority of States have neither adopted the GPTC Guide's leak grading and repair criteria, nor have regulatory requirements supplementing the requirements for leak grading or leak repair in part 192. A few States (such as Texas, Kentucky, Massachusetts, and New York) have adopted leak grading and repair standards similar to those in the GPTC Guide. But many more States reported to NAPSR that they automatically adopt PHMSA's pipeline safety regulations for leak grading and repair into their regulations and do not otherwise introduce more stringent requirements. Some of those States noted that they assume some operators follow the guidance in the GPTC Guide on the grading and repair of leaks described in section II.D.8. Few States have specific requirements for replacement of gas pipelines known to leak based on material, design, or past operating and maintenance history; among those States, replacement initiatives generally focused on gas distribution pipelines rather than gas gathering or transmission pipelines.

Of that minority of States that have regulations exceeding the current requirements in part 192 for grading and repairing leaks, most indicated that they followed a grading system resembling the GPTC grading system, where they classify leaks as grade 1, grade 2, or grade 3 based on relative safety hazards. However, these States may not impose leak grading and repair requirements uniformly across each type (gathering, transmission, and distribution) of pipeline. Mandatory repair timelines also differed among those States—particularly with respect to grades 2 and 3 leaks.

With respect to grade 2 leaks, some States do not have specific requirements for monitoring and repair and defer to operator procedures. Other States noted they require operators to recheck these leaks on subsequent surveys, per an operator's procedures. Some States have requirements for operators to reassess grade 2 leaks every 6 months, with a few States requiring additional (or monthly) surveys until the leaks are cleared. There is also a wide variety of State approaches to repair timelines for grade 2 leaks: the States largely require the repair of grade 2 leaks anywhere from 12 months to 24 months after the date of discovery, with a handful of States requiring more immediate repairs.

With respect to grade 3 leaks, monitoring requirements for grade 3 leaks also vary widely between those States with grade 3 leak grading and repair requirements, with some States requiring operators to monitor grade 3 leaks every 6 months, and other States requiring operators to monitor grade 3 leaks every 15 months. The States that have requirements for repairing grade 3 leaks follow one of two paths: either the State requires that grade 3 leaks be repaired within a prescriptive timeframe, such as 24, 30, or 36 months after discovery, or the State requires operators to have only a defined maximum number of outstanding grade 3 leaks. Some States only require operators to repair grade 3 leaks if the leaks have a relatively high emission rate. The methods for identifying high-emitting grade 3 leaks vary by State. For example, Massachusetts defines an ''environmentally significant'' grade 3 leak as one with a ''leak extent'' (land area affected by gas migration) of 2,000 square feet or greater, or with a highest barhole reading of 50% or more gas in air and requires its repair within either 2 years or 12 months, depending on the extent of migration. Some States noted that they required operators to perform additional leakage surveys after repairs are completed.

Industry Methane Leak Detection and Repair Practices and Efforts

Pipeline operator leak detection and repair practices are similarly insufficient to meet the risks to the environment and public safety from leaks of methane and other gases from gas pipeline infrastructure. Operators employ a spectrum of approaches and technology in connection with leak detection and repair—most of which are focused on compliance with pertinent Federal and State regulations that themselves inadequately address the public safety and environmental risks arising from all leaks on gas transmission, distribution, and part 192-regulated gathering pipelines. Although recent voluntary industry approaches pertaining to leak detection and repair are welcome, those efforts generally exhibit shortcomings (including meager participation, limited application to different pipeline facilities, absence of meaningful leak reduction targets, or a lack of transparency, limited application to natural gas pipelines), underscoring the need for timely Federal regulatory intervention. Moreover, while progress has been made on efforts to replace or remediate any pipeline known to leak based on material (such as cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history, it remains an issue. For example, according to PHMSA annual reports, 18,314 miles of cast or wrought iron distribution mains and 6,518 service lines remained in operation at the end of 2021.

Individual operators' leak detection and repair programs have historically focused on ensuring compliance with pertinent Federal and State requirements that (as explained above) generally lack meaningful requirements for timely grading and repair of leaks other than ''hazardous leaks.'' For those leaks from gas transmission, regulated gathering, and distribution facilities that are not considered ''hazardous'' under current PHMSA regulations, some operators may incorporate the GPTC Guide leak identification, grading, and mitigation criteria within their inspection and maintenance procedures, using the ''LEAKS'' mnemonic as an aide to their personnel tasked with managing leak detection and remediation.[182] However, not all operators incorporate the GPTC Guide within their inspection and maintenance procedures; similarly, operators who integrate the GPTC Guide in their procedures include revision/amendment to those procedures, or may not adopt those procedures across all types of gas pipelines on their system.

Individual operators employ a range of equipment and technologies, with some operators employing advanced technologies such as infrared technologies, FIDs, and laser gas detectors to satisfy pertinent leakage survey requirements. For example, during the 2021 Public Meeting, a representative from the Knoxville Utilities Board (KUB), a gas distribution pipeline operator and member of the American Public Gas Association (APGA), noted that it performs leakage surveys by using handheld laser leak detectors while walking pipelines or travelling rights-of-ways with a Segway. For its distribution mains, KUB stated that it assesses those pipelines using a mobile method employing a traditional laser detector mounted in a vehicle, driving at lower speeds, and surveying major roads at night. During leakage surveys, if KUB technicians find an indication of a leak, they pinpoint the leak's specific location. If the leak can be fixed with a minor repair—through an adjustment, a tightening, or lubrication—the technicians will make the repair on-site. If the technicians find a grade 1 leak during a survey, KUB stated the technicians stay on-site and provide site safety until a repair crew can make the appropriate, immediate repairs. KUB stated that they repair any discovered grade 2 leaks within 90 days, and grade 3 leaks within 6 months, but they also noted in their presentation during the 2021 Public Meeting that repair schedules can vary from operator to operator. Similarly, Kinder Morgan during the 2021 Public Meeting stated that it employed a variety of methods and technologies (foot patrols; aerial surveys by fixed-wing aircraft or helicopter; automobile-borne sensors when the right-of-way is accessible) to perform right-of-way patrols on its transmission lines. However, these practices are not universal; rather (as explained above), the 2021 Public Meeting underscored that many operators are only beginning to integrate advanced leak detection technologies throughout their systems.

So far, voluntary industry standards have not resulted in operators employing adequate leak detection and repair practices. The non-mandatory Appendix M to ASME B31.8S, ''Gas Transmission and Distribution Piping Systems'' contains leak grading and repair criteria similar to the contents of the GPTC Guide.[183] However, that standard—like the GPTC Guide—specifies neither technology nor performance requirements for operator leak detection programs, and it contains no repair schedule for grade 3 leaks. In addition, PHMSA also understands that not every gas pipeline operator incorporates ASME B31.8–2007 into their inspection and maintenance procedures.

Following the May 2021 Public Meeting, AGA et al. highlighted a handful of the voluntary industry initiatives to reduce methane emissions—including leaks from gas gathering, transmission, and distribution pipelines.[184] However, publicly available information regarding those efforts does not confirm that leaks on gas transmission, distribution, and regulated gathering are detected and repaired in a timely manner. Precisely which pipeline operators and which pipeline facilities are captured by each initiative is generally not clear, but participation is far from universal among operators and pipeline facilities that would be subject to the amendments to part 192 contemplated in this NPRM. And even in those initiatives for which there is publicly available, operator-specific information, the focus is less on pipeline leak detection and repair than on other potential sources of methane emissions (*e.g.,* blowdowns, excavation damages). For example, while the Methane Challenge Best Management Practice Commitment Option documentation describes compressor station equipment leaks, it does not address leak detection and repair on buried pipeline facilities other than recommended replacement of cast iron and bare steel distribution pipelines [185] Indeed, a review of publicly available information on the initiatives identified by AGA et al. does not indicate discrete emissions reduction targets for different operators or types of pipeline facilities. Only a minority of the initiatives identified by industry trade groups publish *any* data on the methane emissions reductions achieved—and that data does not show which specific operators are achieving their performance targets. Publicly available information does not demonstrate that these voluntary initiatives have led to reductions in emissions of methane and other gases.

6. Damage Prevention

Reducing excavation damage to pipelines has historically been a focus of PHMSA's efforts in controlling public safety risks from gas pipelines—but is also an important component of mitigating harmful GHG emissions. Excavation damage creates a safety hazard for the public, the excavator, and the affected pipeline facility operator, and can lead to significant emissions going unnoticed or ignored if not posing an imminent public safety hazard. According to PHMSA data presented by AGA representatives at the 2021 Public Meeting, excavation damage in 2020 alone resulted in the loss of 245,000 MCF of gas from gas distribution pipelines—equivalent to the amount of emissions produced by 34 million miles driven by a vehicle or 50 million pounds of coal burned.[186] PHMSA incident reports have identified incidents caused by excavation damage that was not discovered for some time, or where no excavation work was ever reported.

Nevertheless, some State excavation damage prevention programs may not adequately address these risks. PHMSA has taken steps in recent years to establish and improve comprehensive implementation of State programs

[182] The ''LEAKS'' management system mnemonic consists of Locating the leak, Evaluating its severity, Acting appropriately to mitigate the leak, Keeping records, and Self-assessing to determine if additional actions are necessary to keep the pipeline system safe.

[183] ASME, B31.8–2007, *Gas Transmission and Distribution Piping Systems, 2007 Edition* (2008) (ASME B31.8–2007). PHMSA regulations incorporate by reference elements of ASME B31.8–2007 in connection with yield strength testing procedure (§ 192.619(a)(1)(i)) or the alternative MAOP requirements (§ 192.620)—but not non-mandatory appendix M.

[184] AGA et al. at Appendix A.

[185] *See* EPA, ''Methane Challenge Program BMP Commitment Option Technical Document'' at 10 and 24–28 (May 2022), *https://www.epa.gov/system/files/documents/2022-05/MC_BMP_TechnicalDocument_2022-05.pdf* (last accessed December 18, 2022).

[186] Sames, ''Presentation of AGA at 2021 Public Meeting'' at slide 7 (May 5, 2021), *https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1139.*

designed to prevent damage to underground pipeline facilities. First, PHMSA published a final rule in 2015 establishing procedures at 49 CFR part 198 for evaluating State excavation damage prevention law enforcement programs and enforcing minimum Federal damage prevention standards in States where damage prevention law enforcement is deemed inadequate or does not exist.[187] PHMSA audited State damage prevention programs for adequacy under those new procedures in 2016, determining that 27 States had inadequate damage prevention enforcement programs. Second, PHMSA provides States with damage prevention grants to establish and improve comprehensive State damage prevention programs. Third, PHMSA's maintenance of the NPMS database gives pipeline operators, emergency response personnel and State and Federal regulatory authorities, as well as (to a lesser extent, given restrictions on data access) members of the public, data on location and other material characteristics of gas transmission pipelines, thereby reinforcing Federal and State damage prevention initiatives.

But even in States with robust damage prevention programs, limited information on buried gas pipelines can hamstring efforts to reduce excavation damage and marshal emergency response to any resulting incidents. This is particularly true for gas gathering pipelines. Despite recently expanded requirements that operators of certain gas gathering pipelines maintain sufficient damage prevention programs under § 192.614, PHMSA regulations do not currently require operators of gas gathering pipelines to submit geospatial location data into NPMS. This regulatory gap means that State and Federal regulatory authorities (and even some operators) may have limited understanding of the location of those pipelines, thereby inhibiting damage prevention efforts as well as emergency response in the event of an excavation incident.

E. The Limits of PHMSA Regulation and State and Operator Initiatives in Reducing Intentional Methane Releases From Gas Pipeline Facilities

In section 114 of the PIPES Act of 2020, Congress introduced requirements for operators of gas pipeline facilities to update their inspection and maintenance procedure to provide for the minimization of *all* releases of natural gas from their facilities—including *intentional,* vented emissions—in recognition of the significant environmental harm from those emissions. As described in section II.C, equipment venting, blowdowns, and other vented emissions of methane account for a large portion of the total methane emissions from U.S. natural gas pipeline facilities—particularly natural gas transmission pipelines. However, despite the significant environmental impact of those emissions, PHMSA and State pipeline safety regulations have largely avoided explicit restrictions on vented emissions. Moreover, the absence of robust reporting requirements for those emissions under part 191 inhibits PHMSA's ability to identify systemic issues.

Part 191 does not require any reporting on intentional releases of methane or other gases (regardless of the total volume of gas emitted) unless a release causes death, hospitalization, or significant property damage. Similarly, part 192 and part 193 regulations do not require an operator to minimize intentional releases unless they could give rise to a public safety hazard.[188] These regulatory gaps could permit situations such as pressure relief devices being configured to establish overly-conservative actuation setpoints—resulting in avoidable emissions being released because those pressure relief devices vent methane more frequently than necessary to maintain system pressure within safe operating bands. Incident reports and National Response Center (NRC) reports submitted to PHMSA for pressure relief device malfunctions provide a sense of the magnitude of potential emissions from improperly configured pressure relief devices: each incident can result in the release of millions of cubic feet of methane.

Similar to voluntary leak detection and repair efforts, voluntary industry efforts to reduce emissions from blowdowns fall short in minimizing vented emissions. PHMSA is unaware of any industry-level, voluntary initiatives among operators of part 193 facilities to reduce vented emissions. And voluntary operator efforts among gas pipelines either parallel or directly invoke best practices recommended by the EPA's voluntary methane programs such as the Methane Challenge Program and the Natural Gas STAR programs.[189] For the ''Best Management Practices'' option in the Methane Challenge Program, an operator can commit to cutting pipeline blowdown emissions by at least 50 percent by any of the following methods:[190]

- Routing gas to a compressor or capture system for beneficial use;
- Routing gas to a flare;
- Routing gas to a low-pressure system by taking advantage of existing piping connections between high- and low-pressure systems, temporarily resetting or bypassing pressure regulators to reduce system pressure prior to maintenance, or installing temporary connections between high and low-pressure systems; or
- Utilizing hot tapping, a procedure that makes a new pipeline connection while the pipeline remains in service, flowing natural gas under pressure, to avoid the need to blowdown gas.

The voluntary industry emissions reduction efforts above cannot boast universal participation, but they hint at the potential for significant reductions in vented emissions if applied across all gas pipeline facility operators. In 2019 alone, a mere 8 participants in the EPA's Methane Challenge transmission pipeline blowdown mitigation program, operating 29 gas transmission pipeline facilities, reduced emissions by 1.9 million metric tons of CO_2 equivalent estimated by calculation or measurement in accordance with 40 CFR part 98, subpart W or, for non-subpart W facilities, an alternative method.[191]

III. Federal Efforts To Address Climate Change by Reducing Methane Emissions

The urgency of reducing methane emissions to stave off or avoid the worst

[187] PHMSA, ''Pipeline Safety: Pipeline Damage Prevention Programs—Final Rule,'' 80 FR 43835 (July 23, 2015).

[188] *See, e.g.,* §§ 192.169 and 192.617(a)(2) (requiring discharge piping for compressor station pressure relief devices and emergency shutdown systems vent to locations that would avoid public safety hazards) and 192.199(e) (requiring pressure relief and limiting devices have discharge stacks, vents, or outlet ports be located where gas can be discharged into the atmosphere without undue hazard).

[189] EPA, ''Voluntary Methane Programs for the Oil and Natural Gas Industry,'' *https://www.epa.gov/natural-gas-star-program* (last accessed June 20, 2022). In 2018, members of the Interstate Natural Gas Association of America (INGAA) agreed to adopt voluntary commitments to minimize methane emissions from member transportation and storage assets, including a commitment to reduce emissions from blowdowns when repairs need to be made. The aforementioned EPA programs and two industry initiatives, the ONE Future Coalition and the Environmental Partnership, are featured prominently in the INGAA commitments. The full list of commitments is available on INGAA's website (*https://www.ingaa.org/File.aspx?id=38523&v=6553c6c8#:~:text=As%20part%20of%20our%20ongoing,build%20a%20cleaner%20energy%20future*) (last accessed July 20, 2022).

[190] EPA, ''Natural Gas STAR Methane Challenge Program BMP Commitment Option Technical Document'' at 21 (May 2022).

[191] EPA, ''Methane Challenge Program Accomplishments,'' *https://www.epa.gov/natural-gas-star-program/methane-challenge-program-accomplishments* (last accessed July 20, 2022).

effects of climate change, coupled with the inability of existing Federal, State, and industry efforts to rise to that challenge, have catalyzed responses by the Federal legislative and executive branches to reduce unintentional and vented methane releases from gas pipeline facilities. Those efforts, which are discussed below, inform the regulatory amendments proposed in this NPRM.

A. The PIPES Act of 2020

The PIPES Act of 2020, which was signed into law with broad bipartisan congressional and widespread industry and stakeholder support on December 27, 2020, directed a fundamental shift in PHMSA's regulation of gas pipeline facilities: environmental benefits would join public safety as a principal object of PHMSA regulation.[192] Concerned in particular with the contribution of methane releases from natural gas pipelines to climate change,[193] Congress included within that legislation three sections that would be implemented by this NPRM: sections 113, 114, and 118.

Section 113 of the PIPES Act of 2020 states that the Secretary of Transportation shall issue regulations that require operators of gas transmission pipeline facilities, gas distribution pipeline facilities, and certain regulated gas gathering pipelines in Class 2, Class 3, and Class 4 locations to conduct leak detection and repair programs to meet the need for gas pipeline safety and to protect the environment. Such regulations must include minimum performance standards that reflect the capabilities of commercially available advanced leak detection technologies that are appropriate for the type of pipeline, the location of the pipeline, the pipeline's material of construction, and the product transported by the pipeline. The leak detection and repair programs must be able to identify, locate, and categorize all leaks that are hazardous to human safety or the environment or that have the potential to become explosive or otherwise hazardous to human safety. The regulations must require the use of advanced leak detection technologies and practices through continuous monitoring on or along the pipeline, through periodic surveys with handheld equipment, equipment mounted on mobile platforms, or other commercially available technology. The regulations also must identify any scenarios where operators may use leak detection practices that depend on human senses, and include a schedule for repairing or replacing each leaking pipe, except for a pipe with a leak so small that it poses no potential hazard. Congress also expressly precluded the Secretary from reducing the frequency of surveys or extending the duration of leak repair or remediation timelines as required by PHMSA regulations on the date of enactment of the PIPES Act of 2020. Section 113 does not alter the Secretary's statutory authority to regulate gathering lines. Congress directed PHMSA to issue regulations implementing section 113 no later than December 27, 2021.

Section 114 of the PIPES Act of 2020 adjusts the requirements for inspection and maintenance procedures. This self-executing provision of the statute requires that pipeline operators ensure their inspection and maintenance plans contribute to eliminating hazardous leaks of gases (not limited to natural gas) and minimizing releases of natural gas specifically from pipeline facilities; protect the environment; and address the replacement or remediation of pipelines (including cast-iron, bare-steel, unprotected steel, wrought-iron, and certain plastic pipelines) that are known to leak based on material, design, or past operating and maintenance history. Operators had one year from the date of the enactment of the PIPES Act of 2020 (*i.e.,* no later than December 27, 2021) to update their inspection and maintenance plans to address these self-executing requirements.[194]

Lastly, section 118 of the PIPES Act of 2020 amended the criteria set forth at 49 U.S.C. 60102(b)(5) governing issuance of any new rulemakings to elevate consideration of environmental benefits on par with other (*e.g.,* public safety) anticipated benefits. That statutory amendment reinforced the environmental purpose of section 113 of the PIPES Act of 2020, as well as historical provisions (*e.g.,* 49 U.S.C. 60102(b)(1)(B)(ii) and (b)(2)(A)(3)) within the Federal Pipeline Safety Laws that authorize PHMSA to issue regulations acknowledging the environmental protection benefits from regulation of gas pipeline facilities.

Gas pipeline operators and related trade associations applauded the passage through the Senate and later enactment of the PIPES Act of 2020 as part of the Consolidated Appropriations Act of 2021 (Pub. L. 116–260). For example, API released a statement in support of the Senate's passage of the legislation (S.2999) that became the PIPES Act of 2020, stating that the ''PIPES Act takes important steps to make pipelines safer for surrounding communities and the environment.''[195] Following enactment, INGAA described the PIPES Act of 2020 as a ''historic piece of legislation'' that ''enhances pipeline safety, embraces the latest technologies, and aids in the further reduction of methane emissions.''[196] At the 2021 Public Meeting, AGA et al. expressed support for the PIPES Act of 2020 and initiatives that protect the public and the environment, noting that their members have committed to a range of initiatives to reduce methane emissions to achieve goals for addressing climate change.[197]

B. Administration Efforts Confronting the Climate Crisis

The U.S. Federal Government is taking aggressive action in response to climate change. During his first week in

[192] *See* 49 U.S.C. 60102(b)(5).

[193] *See, e.g.,* 166 Cong. Rec. H7305 (Dec. 21, 2020) (memorializing a statement by Rep. Pallone that ''[t]his is a big win in the fight against climate change, along with the reauthorization of the Pipeline Safety Act, which reduces methane leaks.''); ''Press Release from Senate Commerce Committee Leaders Commending Passage of Pipeline Safety Legislation'' (Dec. 22, 2020), *https://www.commerce.senate.gov/2020/12/committee-leaders-commend-passage-of-pipeline-safety-legislation* (quoting Sen. Cantwell as stating ''This legislation also ensures that the latest technology will be used to detect and prevent costly methane leaks, which is especially important because methane leaks are a significant hazard and a major contributor to global warming.'').

[194] Section 114 also requires the Government Accountability Office to conduct a study to evaluate the procedures used by PHMSA and States when evaluating operators' inspection and maintenance plans, and subsequently issue a report regarding the findings of the study and recommendations for how to further minimize releases of natural gas from pipeline facilities without compromising pipeline safety. Additionally, the Secretary is to, not later than 18 months after the enactment of the PIPES Act of 2020, submit to Congress a report discussing the best available technologies or practices to prevent or minimize the release of natural gas, without compromising pipeline safety, when making planned repairs, replacements, or maintenance to a pipeline facility; or when intentionally venting or releasing natural gas, including when blowing down pipelines. The report must also discuss whether pipeline facilities can be designed, without compromising pipeline safety, to mitigate the need to intentionally vent natural gas.

[195] API, Press Release, ''API Statement of Senate Passage of PIPES Act (Aug. 6, 2020), *https://www.api.org/news-policy-and-issues/news/2020/08/06/api-statement-on-senate-passage-of-pipes-act.*

[196] INGAA, Press Release, ''INGAA Hails Passage of Historic Pipeline Safety Reauthorization Bill in 2021 Omnibus Package'' (Dec. 21, 2020), *https://www.ingaa.org/News/PressReleases/38353.aspx* (quoting President and CEO of INGAA, Amy Andryszak, praising Congress's direction to PHMSA to update its regulations ''to reflect the latest technologies and practices [to] . . . both enhance safety and benefit the environment'').

[197] Sames, Cristina. Pipeline Leak Detection, Leak Repair, and Methane Emissions. AGA. May 5, 2021. Briefing materials, recordings, and transcripts of the 2021 Public Meeting are available on the web page for the meeting at *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=152.*

office, President Biden established the National Climate Task Force, assembling leaders from across Federal agencies—including the Secretary of Transportation—to enable a whole-of-government approach to combatting the climate crisis.[198] Essential in those efforts are a spectrum of regulatory actions being undertaken across the U.S. Federal Government to reduce methane emissions described in the U.S. Methane Emissions Reduction Action Plan published in November 2021.[199] Parallel proposals by EPA and PHMSA to reduce methane emissions from natural gas infrastructure occupy a critical role in the Administration's whole-of-government strategy for tackling the climate crisis.

1. Pertinent Executive Orders

Several recent E.O.s direct PHMSA and other Federal agencies to undertake efforts to achieve substantial reductions of methane emissions from the oil and gas sector as soon as possible.

Executive Order 13990

On January 20, 2021, the President signed E.O. 13990, titled ''Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis'' [200] announced the Administration's re-commitment to environmental justice, science-based decision-making, protecting public health and the environment, and ensuring Federal agency actions account for the benefits of reducing climate pollution. Toward that end, E.O. 13990 directed all executive departments and agencies to immediately review and, as appropriate and consistent with applicable law, take action to address the promulgation of Federal regulations and other actions during previous years that conflict with these important national objectives, and to immediately commence work to confront the climate crisis.

Executive Order 14008

On January 27, 2021, the President signed E.O. 14008, titled ''Tackling the Climate Crisis at Home and Abroad.'' [201] E.O. 14008 puts ''the climate crisis at the center of U.S. foreign and domestic policy,'' with a focus on a multilateral approach to putting the world on a sustainable climate pathway and building resilience, both at home and abroad, against the impacts of climate change. Abroad, E.O. 14008 expresses the Administration's intent for the United States to exercise its leadership to meet the climate challenge by recommitting to the Paris Agreement and engaging in international climate summits and forums. Domestically, E.O. 14008 outlines a plan to focus on an all-in approach that considers environmental justice for all communities (especially those that have been underserved in the past), creates clean energy jobs, and builds modern and sustainable infrastructure.

2. Renewal of U.S. Commitments to International Efforts To Address Climate Change

Consistent with the instruction in E.O. 13990, the President returned the United States into the Paris Agreement on January 20, 2021.[202] The Paris Agreement is an agreement within the United Nations (UN) Framework Convention on Climate Change (UNFCCC) addressing climate change mitigation, adaptation, and finance, that was drafted throughout 2015 and was signed in 2016. The Paris Agreement was forged to help the world avoid catastrophic planetary warming and to build resilience around the world to the impacts from climate change that are occurring, with a long-term goal of keeping the rise in global average temperature to below 3.6 degrees Fahrenheit by reducing emissions of GHGs. To achieve these goals, article 4 of the Paris Agreement requires each party to prepare and maintain a ''nationally determined contribution'' of emissions reduction or mitigation targets once every 5 years. As of October 2022, 194 members of the UNFCCC are parties to the agreement; the United States had withdrawn from the agreement in 2020.

Pursuant to section 102(e) of E.O. 14008, the United States also submitted a new Nationally Determined Contribution (NDC), on April 4, 2021, after rejoining the Paris Agreement.[203] In the NDC, the Administration announced an ambitious ''economy-wide target of reducing net greenhouse gas emissions by 50–52 percent below 2005 levels in 2030.'' The NDC includes a specific commitment to address methane emissions by, among other efforts, ''plugging leaks from wells and mains and across the natural gas distribution infrastructure.'' [204] The NDC notes that the United States aims to achieve these targets with a whole-of-government approach at the Federal level and ambitious innovation from State, local, and tribal governments, and private investment.

The United States further reinforced its commitment to reducing methane emissions by joining the European Union and several other countries in committing to the Global Methane Pledge ahead of the 26th global climate summit (the 26th Conference of the Parties, or COP26).[205] In its joint statement with the European Union, the Biden-Harris Administration committed to direct the U.S. EPA and PHMSA to ''reduce methane leakage from pipelines and related facilities,'' [206] and announced that more than 100 countries had joined the Global Methane Pledge and a commitment to reduce the world's methane emissions 30% from 2020 levels by 2030.[207] The Administration has since released a U.S. Methane Emissions Reduction Action Plan detailing its comprehensive whole-of-government plan to reduce methane emissions through a combination of regulatory actions, financial incentives, increased transparency and data disclosure, and public and private

[198] White House, ''Fact Sheet: President Biden Takes Executive Actions to Tackle the Climate Crisis at Home and Abroad, Create Jobs, and Restore Scientific Integrity Across Federal Government'' (Jan. 27, 2021), *https://www.whitehouse.gov/briefing-room/statements-releases/2021/01/27/fact-sheet-president-biden-takes-executive-actions-to-tackle-the-climate-crisis-at-home-and-abroad-create-jobs-and-restore-scientific-integrity-across-federal-government/.*

[199] White House Office of Domestic Climate Policy, *U.S. Methane Emissions Reduction Action Plan* (Nov. 2021), *https://www.whitehouse.gov/wp-content/uploads/2021/11/US-Methane-Emissions-Reduction-Action-Plan-1.pdf;* White House Office of Domestic Climate Policy, *Delivering on the U.S. Methane Emissions Reduction Action Plan* (Nov. 2022), *https://www.whitehouse.gov/wp-content/uploads/2022/11/US-Methane-Emissions-Reduction-Action-Plan-Update.pdf.*

[200] 86 FR 7037 (Jan 25, 2021).

[201] 86 FR 7619 (Feb 1, 2021).

[202] *https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement. https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement.*

[203] UNFCCC, Nationally Determined Contribution Registry (Interim), ''The United States of America Nationally Determined Contribution'' (April 4, 2021).

[204] UNFCCC, Nationally Determined Contribution Registry (Interim), ''The United States of America Nationally Determined Contribution'' at 5 (April 4, 2021).

[205] ''Joint U.S.-EU Statement on the Global Methane Pledge'' (Oct. 11, 2021), *https://www.state.gov/joint-u-s-eu-statement-on-the-global-methane-pledge/https://www.state.gov/joint-u-s-eu-statement-on-the-global-methane-pledge/.*

[206] White House, ''Joint U.S.-E.U. Press Release on the Global Methane Pledge'' (Sept. 18, 2021), *https://www.whitehouse.gov/briefing-room/statements-releases/2021/09/18/joint-us-eu-press-release-on-the-global-methane-pledge/.*

[207] ''Fact Sheet: President Biden Tackles Methane Emissions, Spurs Innovations, and Supports Sustainable Agriculture to Build a Clean Energy Economy and Create Jobs'' (Nov. 2, 2021), *https://www.whitehouse.gov/briefing-room/statements-releases/2021/11/02/fact-sheet-president-biden-tackles-methane-emissions-spurs-innovations-and-supports-sustainable-agriculture-to-build-a-clean-energy-economy-and-create-jobs/.*

partnerships.[208] The Administration continues to lead nations around the globe in methane reduction efforts, including by reconvening the Major Economies Forum on Energy and Climate (MEF) on multiple occasions. The President reconvened the MEF most recently on June 17, 2022, to encourage participant countries to accelerate emissions reduction progress and provide a forum for participants to share the results of their Global Methane Pledge efforts.[209] The regulatory requirements proposed in this NPRM would help align the United States with ongoing efforts from international partners to enhance methane mitigation requirements for gas pipeline infrastructure.[210]

3. EPA's Proposed New Source Performance Standards and Emissions Guidelines for the Oil and Natural Gas Industry

On November 15, 2021, the EPA proposed new source performance standards and emission guidelines for crude oil and natural gas facilities.[211] This action was in response to the January 20, 2021, Executive Order titled ''Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis.'' The 2021 action proposed to update VOC and methane [212] standards on the books for new sources (located at 40 CFR part 60, subparts OOOO and OOOOa),[213] add new standards for new sources (which would be located at 40 CFR part 60, subpart OOOOb), and establish the first nationwide Emission Guidelines for states to regulate methane emissions from existing sources (which would be located at 40 CFR part 60, subpart OOOOc).[214] On December 6, 2022, in a supplemental proposal, EPA proposed further updates to its November 2021 proposal.[215] The proposed standards are developed based on the EPA's determination of the ''best system of emissions reduction'' (BSER) under section 111 of the Clean Air Act. The EPA's proposed emission standards, including emissions monitoring, repair, and maintenance requirements, would apply to numerous types of facilities (including pneumatic controllers and pumps, storage vessels, and sweetening units amongst others) across a defined source category.[216] Among the gas pipeline facilities within the scope of EPA's 40 CFR part 60 regulatory scheme are compressor stations on gas transmission pipelines and boosting stations on gas gathering pipelines.

C. PHMSA Implementation of the PIPES Act of 2020

PHMSA's efforts to implement requirements from the PIPES Act of 2020 efforts dovetail with policy goals of the Biden-Harris Administration described above. This proposed rulemaking in particular is a key part of PHMSA's efforts to address these policy priorities and is referenced in the White House ''U.S. Methane Emissions Reduction Action Plan.'' [217]

1. PHMSA's May 2021 Public Meeting

PHMSA held a public meeting on May 5–6, 2021, (2021 Public Meeting) to provide stakeholder groups and members of the public an opportunity to share perspectives on improving gas pipeline methane leak detection and repair programs consistent with sections 113 and 114 of the PIPES Act of 2020. The agenda for the meeting included examining the sources of methane emissions from gas pipeline systems, the current regulatory requirements for managing fugitive and vented emissions, current leak detection and repair practices of the industry, and the use of advanced technologies and practices to reduce methane emissions from gas pipeline systems.

Stakeholders were invited to submit written comments in connection with the 2021 Public Meeting. PHMSA received 7 comments from individual pipeline operators, leak detection technology service providers, public safety groups, and industry trade organizations, as summarized below. The meeting itself included presentations and panel discussions from representatives from PHMSA, EPA, NAPSR, EDF, PST, the United Association of Plumbers and Pipefitters, GPTC, AGA, American Public Gas Association, INGAA, GPA, Pipeline Regulatory Consultants, Gas Technology Institute, the Methane Emissions Technology Evaluation Center (METEC) at Colorado State University, QuakeWrap Inc., Bridger Photonics, Safetylics, ProFlex Technologies, ABB, the Federal Energy Regulatory Commission, and the National Association of Regulatory Utility Commissioners. Presentations, recordings, and transcripts from the meeting are available on PHMSA's public meeting web page.[218] Certain comments made before, during, and after the meeting have been summarized and discussed throughout this NPRM.

2. June 2021 Advisory Bulletin

PHMSA published an advisory bulletin on June 10, 2021, calling operators' attention to the self-executing requirements of section 114 of the PIPES Act of 2020.[219] The bulletin advised

[208] White House Office of Domestic Climate Policy, *U.S. Methane Emissions Reduction Action Plan* (Nov. 2021), *https://www.whitehouse.gov/wp-content/uploads/2021/11/US-Methane-Emissions-Reduction-Action-Plan-1.pdf.*

[209] *https://www.whitehouse.gov/briefing-room/statements-releases/2022/06/18/chairs-summary-of-the-major-economies-forum-on-energy-and-climate-held-by-president-joe-biden/.* At this meeting of the MEF, the United States and the EU announced a new Global Methane Pledge Energy Pathway which ''aims to encourage all nations to capture the maximum potential of cost-effective methane mitigation in the oil and gas sector and to eliminate routine flaring as soon as possible, and no later than 2030.''

[210] For example, the European Union in December 2021 proposed legislation that would require member states to impose requirements that, at a minimum: (1) call for use of leak detection technologies with a minimum sensitivity comparable to those proposed in this rulemaking; (2) require leaks of at least 500 ppm to be immediately repaired or replaced and leaks of less than 500 ppm to be repaired or replaced within at least 3 months; and (3) create a default prohibition on all venting of methane (subject to certain exceptions). *See* European Parliament, ''EU Briefing—Fit for 55 Package: Reducing Methane Emissions in the Energy Sector'' (Mar. 2022), *https://www.europarl.europa.eu/RegData/etudes/BRIE/2022/729313/EPRS_BRI(2022)729313_EN.pdf.* Similarly, Canada in September 2022 issued a national Methane Strategy outlining policy options for reducing methane emissions from natural gas pipeline infrastructure. *See* Envt. & Climate Change Canada, *Faster and Further: Canada's Methane Strategy* (Sept. 2022), *https://publications.gc.ca/collections/collection_2022/eccc/En4-491-2022-eng.pdf.*

[211] EPA, ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,'' 86 FR 63110 (Nov. 15, 2021).

[212] EPA regulates greenhouse gases expressed in the form of limitations on methane.

[213] 40 CFR part 60, subpart OOOO regulates VOC only. 40 CFR part 60, subpart OOOOa regulates both VOC and methane.

[214] The proposed Emission Guidelines would address methane only.

[215] EPA, ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,'' 87 FR 74702 (Dec. 6, 2022) (EPA SNPRM).

[216] The EPA defines the Crude Oil and Natural Gas source category to mean (1) crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station. For purposes of EPA's proposed rulemaking, for crude oil, the EPA's focus is on operations from the well to the point of custody transfer at a petroleum refinery, while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the ''city-gate''.

[217] White House Office of Domestic Climate Policy, *U.S. Methane Emissions Reduction Action Plan* (Nov. 2021).

[218] *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=152.*

[219] PHMSA, ''Pipeline Safety: Statutory Mandate to Update Inspection and Maintenance Plans to Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas from Pipeline

operators of pipeline facilities to update their inspection and maintenance plans to address the elimination of hazardous leaks and minimize gas releases from their pipeline facilities, including intentional venting during normal operations. The bulletin also noted that, per the statutory mandate, operators must revise their plans to address the replacement or remediation of pipeline facilities that are known to leak based on their material, design, or past operating and maintenance history. The advisory bulletin noted that the PIPES Act of 2020 requires pipeline facility operators to complete these updates by December 27, 2021.

3. February 2022 PHMSA Webinar Addressing Inspection of Operators' Plans To Eliminate Hazardous Leaks, Minimize Releases of Methane, and Remediate or Replace Leak-Prone Pipe

On February 17, 2022, PHMSA held an informational public webinar reviewing the requirements for pipeline operator inspection and maintenance plans introduced by section 114 of the PIPES Act of 2020.[220] This webinar was informational, with attendees having the opportunity to submit written comments to the public meeting docket. More than 1,500 individuals registered for the public webinar, including representatives from the gas gathering, transmission, and distribution sectors. During the webinar, PHMSA discussed key elements of the new section 114 requirements and reviewed the applicable timelines for the actions required under section 114. PHMSA also discussed its planned approach to inspection of operators' programs and procedures to reduce methane emissions and replace or remediate leak-prone pipes.

IV. Summary of Proposals

A. Leakage Survey and Patrol Frequencies and Methodologies

Existing Federal regulations in subpart M of part 192 are focused primarily on avoiding risks to public safety posed by of instantaneous, large-volume releases or accumulated gas from gas pipelines, with less attention given to environmental harms from methane leaks to the atmosphere and releases of other flammable, toxic or corrosive gases. Part 192 imposes leakage survey and patrol periodicities based on the magnitude and probability of those public safety risks (via the proxies of class location, business districts, and potential impact radius), with operators required to conduct leakage surveys only once per calendar year but with an interval between surveys not to exceed 15 months for most gas transmission pipelines, offshore gathering, distribution pipelines inside of business districts, and some onshore part-192 regulated gathering pipelines; distribution pipelines outside of business districts are obliged to conduct surveys only once every five years. Sections 192.706 and 192.723 outline requirements for leakage surveys (including periodicity) on gas transmission and gas distribution pipelines, respectively, and all offshore, Types A and B gas gathering and certain Type C gathering pipelines must follow the § 192.706 leakage survey requirements for gas transmission lines. Those existing prescribed periodicities are described in further detail below.

Current regulations do not specify what technologies or equipment must be used in the performance of leakage surveys, and most gas gathering and transmission pipelines are exempt from odorization requirements that could help identify leaks. Currently, leakage surveys on all distribution lines and certain unodorized gas transmission and gathering pipelines must be performed using ''leak detection equipment,'' but this term is not currently defined in part 192. PHMSA has historically declined to establish technology or performance standards regarding leak detection equipment. Leakage surveys on transmission pipelines in Class 1 or Class 2 locations or Class 3 and Class 4 locations that are odorized can rely entirely on human senses such as smell or sight. This NPRM proposes to set more specific technical standards for leak detection equipment used for leakage surveys, and these are described in detail in section IV.B of this NPRM.

PHMSA regulations currently require only annual right-of-way patrols on most gas transmission, offshore gathering, and Type A-regulated onshore gathering lines. Patrols are visual surveys and do not require the use of any equipment. Sections 192.705 and 192.721 define right-of-way patrolling requirements for gas transmission, (as well as offshore and Type A gathering), and distribution pipelines, respectively. While offshore and Type A gas gathering pipelines are subject to the same requirements as transmission lines, Types B and C gathering pipelines are not subject to any patrolling requirements. Patrols are typically reliant on human senses (vision, sound, or scent) and do not require the use of leak detection equipment (although operators may incorporate leak detection equipment at their discretion). An operator may combine a patrol with a leakage survey, provided their procedures include both a visual survey of the right-of-way and a leakage survey with leak detection equipment. Patrols can detect unsafe conditions that may indicate a current or future leak or incident. For example, visual right of way patrols can identify construction activity that signifies a potential excavation damage threat, earth and water movement that may indicate a natural force damage threat, or population growth that may indicate change in class location, change in HCA or Moderate Consequence Area status, and higher potential consequences of an incident. Patrols can also detect certain leaks by odor, by detecting dead vegetation, or by other indicia (*e.g.,* bubbles from an offshore, submerged pipeline). However, those approaches entail their own limitations; for example, reliance on smell would not be effective unless the gas contains odorants and vegetation surveys are only effective in certain soil and climate conditions (and completely ineffective in areas with no or sparse vegetation such as paved areas or deserts), and a noticeable impact on vegetation from a leak may lag substantially behind the leak's emergence.

The limitations of PHMSA's existing leakage survey and patrol regulations thus currently allow for extended periods of time during which leaks can degrade into catastrophic integrity failures, allow gas to build up and ignite, or emit a substantial amount of methane or other (flammable, toxic or corrosive) gases to the environment. For gas gathering lines conveying unprocessed natural gas, the risks to public safety and the environment from infrequent (or non-existent) leak survey requirements are particularly acute as any leaks releasing VOCs and HAPs, such as benzene, and corrosive materials entrained with the unprocessed natural gas can expedite degradation of pipeline integrity. And leaks of toxic or corrosive gases from other gas pipeline facilities can adversely affect environmental resources. The environmental impacts of gas pipeline leaks and the estimated environmental and public safety benefits of the requirements proposed herein are discussed in further detail in section 5 of the Preliminary RIA for this NPRM, available in the rulemaking docket. Further, the widespread use of human senses in leakage surveys is a missed opportunity to leverage existing

Facilities,'' 86 FR 31002 (June 10, 2021) (ADB–2021–01).

[220] PHMSA's presentation during this webinar and a recording of the webinar meeting are available on PHMSA's public meeting web page at *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=159.*

commercially available leak detection technology to protect against these risks to public safety and the environment by ensuring that leaks are identified and addressed in a timely manner. In addition to the public safety and human health risks of undetected methane leaks, long intervals between surveys also result in increased emissions of methane or other flammable and toxic gases. For example, in a presentation on the Fugitive Emissions Abatement Simulation Toolkit (FEAST) model at the 2021 EPA Methane Detection Technology Workshop, modeling based on controlled tests and field evaluations demonstrated that at a given detection threshold, survey frequency is directly proportional to fugitive emissions reductions.[221] While the modeling shows decreasing emissions abatement returns to increasing survey frequency, large drop-offs begin to appear only after semiannual OGI surveys.

PHMSA therefore proposes to strengthen minimum leakage survey frequencies for gas transmission and gathering pipelines located in HCAs, aboveground offshore gas transmission and gathering pipelines, distribution pipelines outside of business districts, and distribution pipelines at a high risk of leakage. PHMSA also proposes to introduce patrolling requirements for Type B and Type C gathering pipelines and to increase the minimum patrolling frequency for all gas transmission, offshore gathering, and Type A regulated onshore gas gathering pipelines. Finally, while all operators may supplement instrumented leakage surveys with visual and other sensory survey techniques, PHMSA proposes to limit the exclusive use of human senses for leakage surveys to submerged offshore gas transmission and submerged offshore gas gathering pipelines and, subject to notification to and review by PHMSA, onshore gas transmission and regulated onshore gas gathering pipelines in Class 1 and Class 2 locations outside of HCAs. These amendments would ensure timely detection of leaks. The proposed changes to patrolling frequency would also increase the likelihood that conditions that could result in leaks, potentially fatal incidents, or damage that could result in shutdowns and maintenance-related releases of methane to the atmosphere are detected.

These proposals (and all other proposed amendments to parts 191 and 192) apply generally to pipeline transportation of any ''gas,'' defined in §§ 191.3 and 192.3 as ''natural gas, flammable gas, or gas which is toxic or corrosive.'' Although natural gas pipelines constitute the vast majority of part 192-regulated gas pipeline mileage today, the requirements for ''gas'' pipelines in parts 191 and 192 apply equally to pipelines transporting other gases, including over 1,500 miles of hydrogen gas pipelines in operation today.[222] Unless otherwise specified in the proposed amendments, the proposals in this NPRM apply the same requirements to hydrogen gas pipelines (and other gas pipelines) as to natural gas pipelines. PHMSA invites comment on whether, within a final rule in this proceeding, there would be value in adopting hydrogen gas pipeline-specific provisions (in lieu of or in addition to the provisions proposed herein). Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

PHMSA has not proposed in this NPRM to establish minimum leakage survey frequencies or leak detection equipment requirements for UNGSFs. This approach is consistent with current PHMSA regulations at § 192.12, which do not require UNGSFs perform periodic leakage surveys with leak detection equipment but rather oblige operators of UNGSFs to perform an integrity assessment of each reservoir, cavern, and well as often as necessary (but with a maximum interval between assessments that does not exceed 7 years). Additionally, consensus industry standards[223] incorporated by reference in § 192.12 include recommendations and requirements for periodic UNGSF reservoir and wellsite inspection and monitoring. However, PHMSA invites comment on whether, within a final rule in this proceeding, there would be value in prescribing leakage survey frequency and leak detection equipment requirements for UNGSFs in § 192.12. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

1. Distribution—§ 192.723

Section 192.723 outlines the current requirements for leakage surveys on gas distribution systems. Leakage surveys on distribution pipelines must be performed using leak detection equipment. Leakage surveys in business districts must be performed at least once each calendar year, with an interval between surveys not to exceed 15 months. On distribution pipelines outside of business districts that are not cathodically protected and where electrical surveys for corrosion are impractical (*i.e.,* bare steel, unprotected steel, and cast-iron systems), leakage surveys must be performed once every 3 calendar years, with an interval between surveys not to exceed 39 months. All other portions of a distribution system outside of business district must currently be surveyed once every 5 calendar years at intervals not exceeding 63 months. The term ''business district'' is not defined. PHMSA invites comment on potential criteria for defining the boundaries of a business district for potential inclusion within a final rule in this proceeding. Comments on these potential criteria are especially helpful if they address the potential safety and environmental benefits and potential costs of a proposed or alternative approach, including whether each proposal would be technically feasible, cost-effective, and practicable.

As described in section III.C, fugitive emissions from leaks represent the vast majority of total methane emissions from natural gas distribution systems. However, the current § 192.723 neither articulates minimum performance standards for leak detection equipment nor prescribes a particular technology to ensure that all leaks are identified during leakage surveys on distribution pipelines. PHMSA therefore proposes several regulatory amendments that would increase the frequency and effectiveness of leakage surveys to identify and repair leaks on gas distribution pipelines. First, PHMSA proposes that leakage surveys be incorporated within operator ALDPs meeting the minimum performance standards proposed in this NPRM and any detected leaks be graded and repaired consistent with the grading

[221] Ravikumar, Arvind Ph.D. ''FEAST-Based Evaluation of Methane Leak Detection and Repair Programs Using New Technologies.'' EPA Methane Detection Technology Workshop (August 24, 2021). *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop.* Day 2 at 1:33:50.

[222] See PHMSA Interpretation Response Letter No. PI–92–030 (July 14, 1992) (noting PHMSA regulates hydrogen pipelines under part 192); PHMSA, ''Presentation of Vincent Holohan for Workgroup#4: Hydrogen Network Components at December 2021 Meeting'' at slide 11 (Dec. 1, 2021), *https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1227.*

[223] API Recommended Practice 1170, *Design and Operation of Solution-Mined Salt Caverns Used for Natural Gas Storage—First Edition* (July 2015); API Recommended Practice 1171, *Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs—First Edition* (Sept. 2015).

framework in this NPRM (each discussed further in section IV.B). These proposals would better address the leading causes of methane emissions from gas distribution systems by ensuring that leaks are detected and repaired in a timely manner. Second, PHMSA proposes more frequent leakage surveys to promote earlier detection and repair of leaks, thereby improving the environment by reducing emissions from those leaks, and improving the likelihood that leaks are detected before they adversely impact public safety.

As described earlier, distribution leakage surveys are currently required once every 1, 3, or 5 calendar years, depending on the location and design of the pipeline. The 5-year maximum leakage survey interval allows even leaks hazardous to people or property that must be ''repaired promptly'' under current § 192.703 to remain undetected for up to 5 years, often placing the burden on the general public to detect and report potentially hazardous leaks via odor calls. In addition to the potential hazard to public safety and human health, an undetected leak will continue to emit methane to the environment until it is detected and repaired. PHMSA therefore proposes to eliminate the 5-year survey frequency tier by moving leakage surveys outside of business districts from at least once every 5 years into the next frequency category: at least once every 3 calendar years, with an interval between surveys not to exceed 39 months. Leakage surveys inside of business districts would still be required annually. This proposal would increase the frequency of leakage surveys on all distribution pipelines outside of business districts, consistent with the environmental and public safety risks of *any* leaks, while ensuring that operators continue to prioritize frequency of surveys inside of business districts where there is a higher risk to people and property. Combined with the repair requirements proposed in the new § 192.760, which proposes a maximum repair timeline of 24 months for grade 3 leaks, this ensures that operators repair all leaks prior to their next distribution leakage survey, preventing continued growth in the backlog of unrepaired leaks. Some States have adopted similar standards for leakage surveys outside of business districts, for example the Commonwealth of Massachusetts requires leakage surveys outside of ''principal business districts'' at least once every 24-months.[224]

Similarly, due to the increased environmental and safety risks of distribution mains and service lines that are either without cathodic protection, or known to leak based on material, design or past operating and maintenance history, PHMSA proposes to require that operators perform a leakage survey at least once each calendar year with the interval between surveys not to exceed 15 months, mirroring the high-priority survey frequency for unprotected pipelines and pipelines inside of business districts. Currently, such pipelines mut be assessed at the lowest frequencies: once every 3 calendar years for cathodically unprotected distribution pipelines outside of business districts; once every 5 calendar years for all other distribution pipelines outside of business districts; or once every calendar year for all distribution pipelines within business districts. As with distribution pipelines outside of business districts, some States have also adopted enhanced leak survey requirements for leak-prone pipe. For example, the State of Kansas requires annual leakage surveys for cathodically unprotected steel mains and ductile iron mains in class 2, 3, or 4 locations.[225] Consistent with section 114 of the PIPES Act of 2020, materials known to leak include cast iron, unprotected steel, wrought iron, and historic plastics with known issues. As described in the emissions discussion in section II.C, certain materials are responsible for a disproportionate amount of emissions from leaks, with distribution mains composed of such materials being particularly significant sources of emissions. PHMSA's proposal seeks to increase the scrutiny of distribution systems outside of business districts at a high risk of leakage by decreasing survey intervals and targeting materials at a high risk of leakage. PHMSA's proposal also contemplates that distribution pipeline operators would retain the option to establish more frequent leakage surveys than proposed herein within their operations and maintenance procedures or DIMP plans.

The following categories of distribution pipelines outside of business districts would be subject to the proposed annual survey requirement:

- Cathodically unprotected pipelines on which electrical surveys are impracticable, typically bare and unprotected distribution lines;
- Any distribution pipeline protected by a distributed anode system where the cathodic protection survey under § 195.463 showed a deficient reading; and
- Pipelines known to leak based on the material (including, but not limited to, cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history of the pipeline.

PHMSA expects that, in determining whether a plastic pipe material is a ''historic plastic with known issues'' making it at high risk of leaks, operators should consider PHMSA and State regulatory actions and industry technical resources identifying systemic integrity issues on plastic pipe made from particular materials; or manufactured at particular times or by particular companies, or fabricated and installed pursuant to particular processes. By way of illustration, PHMSA issues advisory bulletins cautioning operators regarding the susceptibility of certain historic plastics to systemic integrity issues. In 2007, in response to NTSB findings and data collection performed by the Plastic Pipe Database Committee (PPDC), PHMSA issued Advisory Bulletin ADB–07–01.[226] That advisory bulletin called operators' attention to cracking issues on pipe and components manufactured by Century Utility Products, Inc.; low-ductile inner wall ''Aldyl A'' piping manufactured by Dupont before 1973; polyethylene gas pipe made from PE 3306 resin; Delrin insert tap tees; and caps made of Celcon (polyactal) on Plexco service tees. Similarly, State pipeline safety regulatory actions, PHMSA pipeline failure investigation reports, and NTSB findings can inform operator determinations whether historic plastic pipe is at a high risk of leakage. Industry efforts and resources are another resource for operators in determining whether historic plastic pipe is known to leak. For example, the PPDC publishes data submitted by program participants that incorporates information regarding investigations of materials of concern or potential concern.[227] PHMSA expects that these and other authoritative resources—coupled with an operator's own design expertise and operational and maintenance history—would be adequate for a reasonably prudent operator to determine whether the particular plastic pipe in its distribution systems is at a high risk of leakage.

[224] 220 Code of Massachusetts Regulations 101.06(21)(b).

[225] Kansas Administrative Regulations 82–11–4(b)(34)(b)(2)(i).

[226] ''Pipeline Safety: Updated Notification of Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe-Advisory Bulletin ADB–07–01,'' 72 FR 51301 (September 6, 2007).

[227] APGA, ''Plastic Pipe Database Collection Initiative,'' *https://www.apga.org/programs/plasticpipedata* (last accessed Dec. 20, 2022).

PHMSA invites comment on the value of either explicitly listing (either within part 192 or within periodically-issued implementing guidance) historic plastics known to leak, or deleting the scope qualification ''historic'' from the proposed regulatory text, for the purposes of the proposed annual survey requirement or for replacement under section 114 of the PIPES Act of 2020. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

PHMSA further proposes to require that operators perform a leakage survey of a distribution pipeline segment after extreme weather events or land movement occur that could damage that segment. This survey must be completed within 72 hours of the cessation of the event, described as the time when the location can be safely accessed by operator personnel, or alternatively, within 72 hours of when the pipeline is returned to service. Such a survey could qualify as a periodic survey, and therefore reset the one- or three-year clock until the next required periodic survey. Separately, PHMSA proposes to require operators to investigate existing leaks when ground freezing and other changes in environmental conditions (such as heavy rain or flooding-inducing ground subsidence, erosion, or the installation of new pavement) has occurred that could affect gas venting or migration to nearby buildings. The required investigation would include conducting a leakage survey for possible gas migration, but said survey would not qualify as a periodic survey and would not reset the one- or three-year clock until the next required periodic survey. Each of those changes in environmental conditions can place new stresses on pipeline integrity or can affect how and where gas vents from or migrates through the ground. Therefore, each can cause new leaks or exacerbate or reveal pre-existing leaks on distribution pipelines. These requirements are designed to ensure prompt evaluation of whether environmental changes have exacerbated existing leaks in a way that creates increased risk to public safety and the environment. PHMSA invites comment on whether to require assessments prior to extreme weather events in order for operators to prepare for and prevent resulting leaks.[228] Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

The proposed amendments to gas distribution pipeline leakage survey requirements are summarized in the table below.

SUMMARY OF DISTRIBUTION LEAKAGE SURVEY AMENDMENTS

Facility	Existing	Proposed
Outside of Business Districts	5 years not to exceed 63 months	3 years not to exceed 39 months.
Pipelines known to leak (cathodically unprotected pipe in existing § 192.723).	3 years not to exceed 39 months	Annually, not to exceed 15 months.
Inside Business Districts	Annually, not to exceed 15 months	No change.
Other Proposals	—After environmental changes that can affect gas migration. —Following extreme weather events.	

Note: The most frequent survey would apply.

PHMSA expects its proposed amendments to leakage survey practices would be reasonable, technically feasible, cost-effective, and practicable for affected gas distribution operators. As explained above, operators are already subject to prescriptive periodic leakage surveys and patrols, and individual operators may have more demanding requirements specified within their DIMP plans or as a function of state-imposed requirements; affected operators also have the option to sync their patrol and leakage survey requirements to minimize compliance burdens (provided that the operator includes both a visual survey of the right-of-way and a leakage survey with leak detection equipment). PHMSA's proposed amendments would merely increase prescribed frequencies within Federal regulation as a function of factors (presence of cathodic protection; extreme weather events; material composition, operating and maintenance history) probative of leak susceptibility—and by extension, risks to public safety and the environment. PHMSA further notes that, insofar as those factors employed in the NPRM as bases for increased leakage survey frequency are widely understood to be potential threats to the integrity of gas distribution pipelines, they are among the phenomena that reasonably prudent operators would evaluate, and potentially adopt mitigation measures to address, in ordinary course when implementing current DIMP requirements to protect public safety from releases of (natural, flammable, toxic, or corrosive) pressurized gases from their pipelines and minimize loss of commercially valuable commodities. Additionally, operators would have flexibility (as appropriate for their needs and their pipelines' operational characteristics and environment) in choosing between commercially available, advanced leakage detection equipment satisfying the performance standards proposed in this NPRM for use in those leakage surveys. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the proposed compliance timelines—based on an effective date of the proposed requirements six months after the publication date of a final rule in this proceeding—would provide operators ample time to implement requisite changes in their leakage survey practices and manage any related compliance costs.

In the Preliminary RIA, PHMSA considers an alternative where the 5-

[228] *See, e.g.,* EPA's notice of proposed rulemaking titled ''Accidental Release Prevention Requirements: Risk Management Programs Under the Clean Air Act; Safer Communities by Chemical Accident Prevention,'' 87 FR 53556 (Aug. 31, 2022) (proposing to require, under the Clean Air Act Risk Management Program, that industrial chemical facilities evaluate ways to address natural disasters and consider steps to prevent releases that may result, even before such events occur).

year survey interval outside of business districts is maintained for plastic pipe distribution pipelines without known leak issues. This alternative is not being proposed because while recent-vintage plastic pipe is understood to leak less than cast iron and bare steel, some studies indicate that plastic piping systems may be leaking more than previously thought.[229] PHMSA invites comment concerning the value of more or less frequent leakage surveys of plastic pipe systems, as well as potential means to identify plastic pipe known to leak (*e.g.,* via a surveillance or sampling program) for inclusion within a final rule in this rulemaking proceeding. Likewise, PHMSA seeks comment on the alternative considered in the Preliminary RIA where distribution mains would be required to be surveyed annually; typically, mains are likely to be more accessible to pipeline operators than service lines crossing private property and may therefore be more convenient to survey. Comments on these questions are especially helpful to PHMSA when they are supported by research or operational experience with leaks from plastic pipe systems or distribution mains (as applicable), along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

2. Transmission and Gathering—§§ 192.9, 192.705, and 192.706

Section 192.706 currently requires gas transmission and Types A and B gathering pipelines that are not odorized to be surveyed with leak detection equipment at least twice each calendar year in Class 3 locations, and at least four times each calendar year in Class 4 locations. All other gas transmission, offshore gathering, Type A and Type B gathering, and certain Type C gathering pipelines must be surveyed once each calendar year. For these annual surveys, PHMSA does not require leak detection equipment on gas transmission and offshore gas gathering pipelines; however, § 192.9 requires the use of leak detection equipment for leakage surveys on Type B and Type C gas gathering pipelines. Section 192.705 specifies frequencies for right-of-way patrols along gas transmission, offshore gathering, and Type A gathering pipelines; Types B and C gathering lines are not required to conduct right-of-way patrols by § 192.705.

Consistent with section 113 of the PIPES Act of 2020, PHMSA proposes to require the use of leak detection equipment and practices meeting the ALDP standard in proposed § 192.763 (see section IV.B) for leakage surveys on most onshore gas transmission and Types A, B and C gathering pipelines. Leakage survey by human or animal senses would be permitted for offshore gas transmission and offshore gathering pipelines. Because leaks on submerged offshore pipelines are visibly conspicuous due to bubbles or a sheen of gas condensate on the water's surface, PHMSA is not proposing to require leak detection equipment be used for leakage surveys of submerged offshore pipelines, including platform risers up to the waterline. However, offshore platform piping and riser piping above the waterline would be subject to the same equipment and survey requirements as onshore gas transmission pipelines. Leakage surveys for onshore pipelines would be permitted without the use of leak detection equipment (*i.e.,* with human senses or animal senses) only for gas transmission and Types A, B, or C gathering pipelines in non-HCA, Class 1 and Class 2 locations, and then only with prior notification and review by PHMSA pursuant to § 192.18. Visual surveys and other survey methods depending exclusively on human or animal senses would only be authorized if the operator can demonstrate through tests and analyses included in the notification that the survey method would be effective to meet the ALDP performance standard proposed in § 192.763(b) or (c). For example, a visual vegetation survey would need to include procedures to ensure effective detection, such as ensuing the location of a buried pipeline is determined before a survey and performing vegetation surveys on foot rather than at a distance from a vehicle or aircraft, and would not be approved in areas where vegetation is absent. The notification must also include the survey procedures and qualifications for surveyors. Leaks detected on gas transmission, offshore gathering, and Types A, B, and C gathering pipelines would need to be graded and repaired consistent with the requirements proposed in this NPRM (see section IV.C). PHMSA welcomes comments and data on the efficacy of the exclusive use of human senses for leakage surveys, particularly on submerged offshore gas transmission pipelines, submerged offshore gas gathering pipelines, onshore gas transmission pipelines, and regulated onshore gas gathering pipelines (for potential inclusion within a final rule in this proceeding). Comments and data on this question are especially helpful to PHMSA when they are supported by research or operational experience with the exclusive use of human senses for leakage surveys, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

As explained in section II.C above, leaks from natural gas transmission line pipe are not as significant a source of methane emissions compared with venting, blowdowns, and leaks from compressor stations and other aboveground equipment. However, as explained above in connection with leakage surveys on gas distribution lines, any leaks of methane contribute to climate change and can entail public safety risks—risks that are each more acute for gas transmission pipelines, which generally operate at higher pressures and capacity than distribution pipelines and are usually not odorized. Further, leaks from gas pipeline facilities transporting other flammable, toxic, or corrosive gases can entail significant public safety and environmental consequences. PHMSA therefore proposes, to support more timely detection and repair of leaks that pose a safety hazard, an increase in the minimum leakage survey frequencies for each of the following, calibrated based on a pipeline's proximity to occupied buildings or HCAs: for gas transmission, offshore gathering, and Type A, B, and C gathering pipelines located in HCAs from once each calendar year to twice each calendar year (at intervals not exceeding 7½ months) if within a Class 1, Class 2, or Class 3 location; and for gas transmission and Types A or B gathering pipelines located within Class 4 locations within HCAs, from once each calendar year to four times each calendar year (at intervals not exceeding 4½ months). For gas transmission and Type A or B gas gathering pipelines that are (consistent with the proposed revisions herein to § 192.625) not odorized, more frequent leak surveys would continue to be required to account for the greater risks to public safety from their proximity to occupied buildings: no less than twice each calendar year (at intervals not exceeding 7½ months) for pipelines in Class 3 locations, and no less than four times each calendar year (at intervals not exceeding every 4½ months) in Class 4 locations. Leaks on gas transmission pipelines, especially in Class 3 and Class 4 locations, would also be subject to more stringent grading requirements

[229] Weller et al., 2020, for example.

in the proposed leak grading and repair requirements described in section IV.C.

As explained in section II.C above, fugitive methane emissions from natural gas compressor stations on gas transmission and gas gathering pipelines comprise a significant share of fugitive emissions from those facilities. Other pipeline facilities with relatively complex design and configuration—such as valve sites (including the valve components, flanges, and tie-ins with line pipe), in-line instrument (ILI) launchers and receivers, and tanks—have fugitive emissions profiles better resembling compressor stations than line pipe. PHMSA therefore proposes more frequent leakage surveys for each of those facilities on gas transmission, offshore gathering, and Types A, B, and C gathering pipelines. Such facilities in Class 1, Class 2, and Class 3 locations would need to be surveyed twice each calendar year (at intervals not exceeding 7½ months), compared with once per year under current regulations. This is the same survey interval used for fugitive methane emissions monitoring for compressor stations under the existing and proposed EPA requirements (for example, 40 CFR 60.5397a(g)(2) for new sources). More frequent leakage surveys for such facilities would ensure operators detect and repair leaks earlier, reducing total emissions and reducing the risk that a leak can degrade into a rupture or other incident. Facilities in Class 4 locations would need to be surveyed at least 4 times each calendar year (at intervals not exceeding 4½ months) due to the potential for comparatively more significant public safety risks in the event of a leak due to their proximity to ignition sources and densely occupied buildings.

SUMMARY OF TRANSMISSION AND REGULATED GATHERING LEAKAGE SURVEY AMENDMENTS

Facility	Existing	Proposed
Non-odorized Class 3	Twice a year not to exceed 7½ months	No change.
Non-odorized Class 4	Four times a year not to exceed 4½ months	No change.
All other transmission	Once a year not to exceed 15 months	No change.
HCA class 1, 2, or 3	No specific standard	Twice a year not to exceed 7½ months.
HCA class 4	No specific standard	Four times a year not to exceed 4½ months.
Valves, flanges, pipeline tie-ins with valves and flanges, ILI launcher and ILI receiver facilities, and leak prone pipe.	No specific standard	Same as proposed HCA frequencies.
Leak detection equipment	Only required for non-odorized class 3 and class 4.	Required except for non-HCA class 1 and class 2 with a notification.
Regulated gathering	Existing transmission line requirements apply to offshore, Type A, Type B, and certain Type C gathering lines.	Require proposed leakage survey requirements for all regulated gathering lines.

Note: The most frequent survey would apply.

PHMSA also proposes to increase the frequency of patrols on gas transmission, offshore gathering, and Types A, B, and C gathering pipelines by replacing the current, scaled approach within § 192.705(b) of between one and four patrols per year based on class location and the presence of a highway or railroad crossing with a global, baseline requirement for those operators to perform 12 patrols along the entirety of their pipelines each calendar year (at intervals not exceeding 45 days). Patrols are primarily visual surveys of the right of way and may be performed with or without leak detection equipment. PHMSA understands those increased frequencies to be appropriate because patrols are valuable not only for identifying existing leaks and incidents, but also because they are a relatively low-cost method for preemptive identification and mitigation of potential threats to pipeline integrity. In conducting patrols, operators should consider potential threats such as right of way incursions (such as construction, excavation, or agricultural activities), signs of earth movement or flooding, or the presence of new structures potentially indicating a change in class location. In addition to the general leak detection and pipeline integrity benefits associated with performing right of way patrols described in section IV.A.2, requiring patrols provides an opportunity to update class location surveys and potential impact circle surveys. PHMSA further notes that operators can control their compliance burdens from the proposed increased patrols by coupling them with other operations and maintenance tasks such as leakage surveys (provided that the operator includes both a visual survey of the right-of-way and a leakage survey with leak detection equipment) or by leveraging mobile technologies.

PHMSA expects its proposed amendments to leakage survey and right-of-way patrol practices would be reasonable, technically feasible, cost-effective, and practicable for affected gas transmission and gathering pipeline operators. As explained above, operators of affected gas transmission and gathering pipelines (some of which operators have both gas transmission and gathering pipeline facilities within their systems) are already subject to prescriptive periodic leakage surveys requirements; affected operators also have the option to sync their patrol and leakage survey requirements to minimize compliance burdens (provided that the operator includes both a visual survey of the right-of-way and a leakage survey with leak detection equipment). PHMSA's proposed amendments would merely increase prescribed frequencies within Federal regulation as a function of factors (including location in HCAs and occupied buildings; components/equipment with complex configurations; material composition; operating and maintenance history) probative of leak susceptibility—and by extension, risks to public safety and the environment. PHMSA further notes that, insofar as those factors the NPRM employs as bases for increased leak detection and patrol frequency are widely understood to be potential threats to the integrity of pipelines, they are among the phenomena that reasonably prudent operators would evaluate, and potentially adopt mitigation measures to address, in ordinary course to protect public safety and the environment from releases of pressurized (natural, flammable, toxic, or corrosive) gases from their pipelines and minimize loss of commercially valuable commodities. Additionally, operators would have flexibility (as appropriate for their needs and their pipelines' operational characteristics and environment) in choosing between commercially available, advanced leakage detection equipment satisfying the performance standards proposed in this NPRM for use in those leakage surveys. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the proposed compliance timelines—based on an effective date of the proposed requirements six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite changes in their leakage survey practices and manage any related compliance costs.

3. Leakage Surveys and Patrols for Types B and C Gas Gathering Pipelines—§§ 192.9, 192.705, and 192.706

PHMSA proposes to apply to Types B and C gas gathering pipelines the leakage survey and patrol requirements proposed in this NPRM for gas transmission, offshore gathering, and Type A gathering pipelines.

PHMSA has long recognized the public safety risks associated with gathering pipelines and has general authority under 49 U.S.C. 60102 to issue minimum Federal pipeline safety standards necessary to ''meet the need for gas pipeline safety [. . .] and protect [] the environment.'' For that reason, PHMSA has in the past extended select part 192 requirements—including leak survey requirements at § 192.706—applicable to gas transmission pipelines to a minority (only the largest, or closest to occupied buildings) of the Type C gas gathering pipelines posing the greatest risks to public safety. Existing § 192.9 does not require operators of Type B and Type C gathering pipelines to conduct patrols pursuant to § 192.705.

However, the historical, limited approach in applying §§ 192.705 (patrol) and 192.706 (leakage survey) requirements to Types B and C gathering lines is inadequately protective of public safety and the environment. Recent aerial methane emissions surveys discussed in section II.C above yield that leaks from gas gathering line pipe, the vast majority of which are Type C or Type R pipelines located in Class 1 locations, in particular are a significant contributor to methane emissions. Further, the GHGI data discussed in section II.E reveals that fugitive methane emissions from all types of gas gathering line pipe vastly exceed emissions from gas transmission line pipe both in total and on a per-mile basis. Leaks from gathering line pipe can therefore be correspondingly greater contributors to the climate crisis than leaks from gas transmission line pipe. Further, because natural gas gathering pipelines carry unprocessed natural gas, any leak from those pipelines would release VOCs and HAPs such as benzene to the environment and risk accelerated degradation of pipeline integrity from corrosives entrained in the natural gas. PHMSA understands that leaks from gathering lines transporting other gases that are flammable, toxic, or corrosive could entail significant public safety and environmental consequences as well. Because of these significant risks to public safety and the environment posed by Types B and C gathering lines, PHMSA has proposed that *all* Type C gathering lines be subject to the same § 192.706 requirements governing leakage survey equipment and frequency as gas transmission and Types A and B gathering pipelines. Similarly, PHMSA proposes to require patrol frequencies for Type B and Type C gathering lines identical to the patrol requirements for as transmission and Type A gathering pipelines. PHMSA understands that its proposed extension of these mutually-reinforcing, enhanced patrol and leakage survey requirements would ensure timely prevention, discovery and remediation of leaks on Types B and C gas gathering lines. PHMSA invites comments concerning the value of requiring more or less frequent leakage surveys of transmission and gathering pipelines (for potential inclusion within a final rule in this proceeding). Comments on these questions are especially helpful to PHMSA when they are supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

PHMSA expects its proposed amendments to extend leakage survey and right-of-way patrol practices to all Types B and C gas gathering pipeline operators would be reasonable, technically feasible, cost-effective, and practicable. Patrols and leakage surveys using leak detection equipment are widely-employed tools adopted by reasonably prudent operators in ordinary course for identifying and mitigating leaks on, or threats to the integrity of, pipelines transporting commercially valuable pressurized (natural, corrosive, toxic, or flammable) gases. Precisely for that reason, PHMSA expects that some Types B and C gas gathering pipeline operators affected by this NPRM's proposed requirements for leakage survey and right-of-way patrols may already voluntarily undertake leakage surveys and patrols on their facilities. Those and other operators of Types B and C gas gathering pipelines (some of which operators may also operate either gas transmission or Type A gathering pipelines) may also have pipelines within their systems subject to prescriptive periodic leakage survey and patrol requirements under Federal or State law. PHMSA's proposed amendments would, therefore, better align leakage survey and right-of-way patrol practices and requirements for Types B and C gas gathering lines with requirements for other 192-regulated gas pipelines. Additionally, PHMSA's proposed periodicities for such surveys and patrols would also turn on factors (including location in HCAs and occupied buildings; components/equipment; material composition; operating and maintenance history) well-understood to be probative of leak susceptibility—and by extension, risks to public safety and the environment. Affected operators would also have the option to sync their patrol and leakage survey requirements to minimize compliance burdens (provided that the operator includes both a visual survey of the right-of-way and a leakage survey with leak detection equipment). And operators would have flexibility (as appropriate for their needs and their pipelines' operational characteristics and environment) in choosing between commercially available, advanced leakage detection equipment satisfying the performance standards proposed in this NPRM for use in their leakage surveys. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the proposed compliance timelines—based on an effective date of the proposed requirements six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite leakage survey and patrol practices and manage any related compliance costs.

PHMSA solicits comment on whether it would be appropriate to apply any of the requirements proposed herein to Type R gathering pipelines not currently regulated under part 192. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of that particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

4. Liquefied Natural Gas Facilities—§ 193.2624

Part 193 does not currently require that operators perform periodic surveys of LNG facility components and equipment for methane leakage to the atmosphere. However, as described in section II.C.2, equipment leaks and other fugitive methane emissions are the second largest methane emissions source from LNG storage facilities and the largest methane emissions source from LNG export terminals.

PHMSA therefore proposes a new § 193.2624 to require a quarterly methane leakage survey using leak detection equipment and remediation of any methane leaks discovered in accordance with the operator's maintenance or abnormal operations procedures. Leaks discovered would need to be remediated on a schedule established within those procedures. Methane leakage surveys would only need to be conducted on components and equipment containing methane or LNG in normal operations. PHMSA further proposes a minimum equipment sensitivity requirement of 5 ppm—along with validation and calibration requirements—consistent with the proposed requirements governing the performance of leak detection equipment described in section IV.B below for part 192-regulated gas pipeline facilities. PHMSA expects that these proposed enhanced methane leakage and repair requirements would improve public safety by allowing for timely identification and remediation of potential ignition sources within part 193-regulated LNG facilities, as well as reduce a key source of fugitive GHG emissions from those facilities. Additionally, eliminating product losses results in cost savings that improve the competitiveness of LNG storage and export facilities, further increasing the net benefits of this proposal. PHMSA also proposes that, consistent with its proposed revisions to part 191 leak detection and repair reporting requirements for part 192-regulated gas pipeline facilities, PHMSA would propose conforming revisions to its annual report form for part 193-regulated facilities [230] to ensure meaningful reporting of all methane leaks detected or repaired by operators pursuant to § 193.2624.

PHMSA expects its proposed leakage survey practices would be reasonable, technically feasible, cost-effective, and practicable for affected LNG facility operators. PHMSA notes that some LNG facility operators may operate transmission pipelines supplying natural gas to their facilities; those operators could use their existing leakage survey practices as a foundation for development of leakage survey requirements tailored to their LNG facilities. PHMSA further notes that, insofar as leakage surveys using leak detection equipment are widely understood to be essential tools in identifying and mitigating threats to the integrity of pipelines transporting methane within any gas pipelines, they are among the practices that reasonably prudent operators would adopt in ordinary course to protect public safety and the environment from releases of methane from equipment and components in LNG facilities and minimize loss of a commercially valuable commodity. Additionally, operators would have flexibility in choosing between leakage detection equipment satisfying the performance standard proposed in this NPRM for use in those leakage surveys. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the proposed compliance timelines—based on an effective date of the proposed requirements six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite changes in their leakage survey practices and manage any related compliance costs.

In order to avoid conflicting with existing regulatory requirements and best practices in the National Fire Protection Association standard, ''Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)'' governing the requirements for LNG facilities (NFPA 59A) and other standard practices, PHMSA has not proposed in this NPRM for LNG facilities a comprehensive, advanced leak detection and repair program framework along the lines of that discussed below in section IV.B for part 192-regulated gas pipeline facilities. For example, section 9.3 of the 2001 edition of NFPA 59A,[231] which is incorporated by reference within PHMSA regulations at § 193.2801, requires continuous gas monitoring in the vicinity of LNG process equipment, and section 12.4.2 requires an alarm at 25% LEL or less. Additionally, certain equipment in LNG plants that are not part of distribution systems may be subject to EPA leak detection and repair requirements in 40 CFR part 60 depending on the purpose and contents of the equipment. However, facilities storing or carrying natural gas or LNG are typically subject to the standards for gas production and transmission systems in 40 CFR part 60. The subpart OOOO and OOOOa standards are described in greater detail in section IV.C.3 and include semiannual fugitive emissions monitoring surveys and repair of all leaks visible with an OGI device or that produce an instrument reading of 500 ppm or greater.[232] For a subpart OOOOa facility, the operator must attempt repair no later than 30 days after detecting the fugitive emissions and must complete the repair within 30 days of the first attempt or during the next scheduled shutdown.[233] Finally, detecting leaks on equipment such as at LNG plants is generally less challenging than doing so on buried pipelines. PHMSA is pursuing a parallel rulemaking (under RIN 2137–AF45) in which it could consider leak monitoring, surveying, and patrolling requirements more holistically.

B. Advanced Leak Detection Programs—§ 192.763

Section 113 of the PIPES Act of 2020 requires PHMSA to issue performance standards for operator leak detection and repair programs reflecting the capabilities of commercially available, advanced leak detection technologies

[230] PHMSA, Form 7300.1–3, ''Annual Report Form for Liquefied Natural Gas Facilities (Oct. 2014). The instructions for Form 7300.1–3 states that ''a non-hazardous release that can be eliminated by lubrication, adjustment, or tightening is not a leak.'' PHMSA, Instructions for Form 7300.1–3 at 4 (Oct. 2014). That historical understanding is inconsistent with PHMSA's understanding of the PIPES Act of 2020 premise that all leaks of methane are hazardous to the environment because they contribute to climate change. PHMSA is not, however, proposing in this NPRM to modify the historical reporting exception with respect to releases of other, non-methane, hazardous materials within an LNG facility.

[231] NFPA, *NFPA–59A: Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)—2001 Edition* (2001).

[232] 40 CFR 60.5397a(a)(1) and (h).

[233] 40 CFR 60.5397(h).

and practices. To satisfy this mandate, PHMSA proposes to introduce a new § 192.763 to require operators establish written Advanced Leak Detection Programs (ALDPs) and to establish performance standards for both the sensitivity of leak detection equipment and for the effectiveness of those ALDPs. This new requirement would provide benefits to both public safety and the environment by ensuring that pipeline operators have programs in place to promptly detect and repair leaks of all gas pipelines subject to part 192, thereby reducing harm to public safety and the environment.

An ALDP represents a complementary set of mutually reinforcing technologies and procedures (including analytics) that the operator uses to detect all leaks. PHMSA proposes to require that an operator's written ALDP include four main elements: leak detection equipment employing commercially available advanced technology, leak detection procedures, prescribed leakage survey frequencies, and program evaluation. Note that grading and repairing leaks after investigation is governed by the proposed § 192.760 described in section IV.C of this NPRM. The proposed requirements in this section would apply to operators of all gas distribution lines, gas transmission lines, offshore gathering, and Types A, B, and C regulated onshore gathering pipelines.

PHMSA expects each of the proposed ALDP requirements discussed below would be reasonable, technically feasible, cost-effective, and practicable for all affected gas pipeline operators. PHMSA understands that most operators of gas pipelines that would be subject to those requirements may already employ one or more of its proposed ALDP elements voluntarily because (inter alia) a reasonably prudent operator would in ordinary course employ a systematic, defense-in-depth approach to identifying leaks given the commercial value of, and potential risks to public safety and the environment posed by, the commodities transported (natural gas or flammable, toxic, or corrosive pressurized gases). Alternatively, an operator may employ one of more of PHMSA's proposed ALDP elements as a compliance strategy for existing PHMSA or State leak detection or integrity management requirements. Regardless, PHMSA's proposals build and on those existing practice by creating a common, straightforward regulatory framework for addressing leak detection across all part 192-regulated gas pipelines. Within that common framework, moreover, operators would retain significant flexibility to select (as appropriate for a pipeline's operational needs and operating environment) a suite of mutually reinforcing leak detection equipment, analytics, and practices, satisfying a baseline leak detection performance standard derived from commercially available advanced leak detection technology in a way that minimizes their compliance costs. PHMSA's proposal even contemplates that some operators of gas pipelines may employ (subject to PHMSA review) an alternative performance standard as a function of location or gas commodity being transported. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the proposed compliance timelines—based on an effective date of the proposed requirements six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite protocols, obtain leak detection equipment, and manage any related compliance costs.

1. Leak Detection Technology Standards—§ 192.763(a)(1)

The first element in an ALDP is the leak detection technology that the operator would use to perform leakage surveys, investigate leaks, and pinpoint leak locations. These technology requirements are proposed in § 192.763(a)(1). Each operator's ALDP would include a list of leak detection equipment that the operator uses for leakage surveys, leak investigations, and pinpointing leaks. Consistent with the mandate in section 113 of the PIPES Act of 2020, PHMSA proposes to specify when leak detection equipment would be required and when an operator may rely on methods that rely on human or animal senses. Specifically, the NPRM proposes to amend § 192.723 to require that all leakage surveys on gas distribution pipelines be performed with leak detection equipment in light of the high risk to public safety from distribution pipelines, which are often located in the vicinity of population centers. Additionally, as described in section IV.A.2 of this NPRM, all leakage surveys on onshore gas transmission and gathering pipelines performed under § 192.706 would require the use of leak detection equipment, except when the operator of a gas transmission or gathering pipeline in a Class 1 or Class 2 location determines that a survey using human senses would be sufficient, subject to review by PHMSA, as provided in § 192.706(a)(1). This default requirement that ALDPs of onshore regulated gas gathering, transmission, and distribution operators use leak detection equipment in leakage surveys would enhance operators' ability to identify and repair leaks on pipelines in a timely manner, and therefore minimize releases and prevent leaks from degrading. It would also serve to improve leak detection data to improve the predictive power of leak management programs, integrity management programs, and artificial intelligence services that can identify systemic pipeline design or repair issues.

PHMSA further proposes that any leak detection equipment used must have a minimum sensitivity of 5 ppm or less. A reading of 1% of the lower-explosive limit of methane gas at atmosphere is approximately 500 ppm; a minimum sensitivity of 5 ppm would therefore provide a protective threshold of detection sensitivity. That threshold is also consistent with the performance of commercially available leak detection equipment. Table 2 of the Appendix G–192–11 of the GPTC Guide provides examples of commercially available methane detection technologies and the sensitivity and detection ranges for those technologies. That information is reproduced in the table below. In addition to the devices listed below, OGI cameras, devices that are capable of visualizing methane gas leaks and other fugitive emissions, are commonly used for fugitive emissions monitoring at LNG plants, compressor stations, and other facilities.

METHANE LEAK DETECTION TECHNOLOGIES AND PERFORMANCE

Technology	Sensitivity	Range
Semiconductor	1–100 ppm	0–100 ppm.
Flame Ionization	1 ppm	0–10,000 ppm.

METHANE LEAK DETECTION TECHNOLOGIES AND PERFORMANCE—Continued

Technology	Sensitivity	Range
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.

Although each of the technologies listed above has advantages and limitations that may make it more or less appropriate for leakage surveys on particular gas pipelines or operating conditions, PHMSA's proposed 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 risk of ignition; and flexibility for operators to choose from a baseline of high-quality equipment for their unique needs. For example, PHMSA understands that modern FID units and closed-path IR and laser-based systems are capable of sub-ppm and parts-per-billion detection. However, quality semiconductor sensors and open-path IR devices have important applications despite comparatively lower-sensitivity. Semiconductor sensors are typically much smaller than other detection devices and therefore are useful in confined spaces and other situations where a smaller tool is necessary to access the space. Additionally, semiconductor sensors are often designed to incorporate intrinsically safe features, which minimizes the risk of ignition in situations where a flammable atmosphere may be present. Similarly, some handheld open-path IR systems can have a sensitivity of 5 ppm-meter at its maximum effective range [234] but have the advantage of allowing a surveyor to detect methane plumes from a distance. This allows operator leakage surveyors to safely and efficiently survey facilities that may otherwise be difficult or unsafe to access. However, the proposed leak detection performance standard would generally exclude each of odorant ''sniffers'' used to test the adequacy of odorization, less-sensitive combustible gas indicators, and most gas monitors intended for confined space gas monitoring rather than methane leak detection—even as PHMSA acknowledges such devices may nevertheless be useful in connection with leak grading (pursuant to proposed § 192.760), as tools supplementing ALDP-compliant leak detection equipment, or as authorized pursuant to proposed § 192.763(c).

As discussed throughout this section, other ALDP programmatic requirements backstop any limitations on the ability of particular leak detection technologies to contribute to the program-wide performance standard at § 192.763(b) that an ALDP detects all leaks of 5 ppm or more when measured 5 feet from the pipeline. For example, PHMSA acknowledges that an operator may determine, based on its operational needs or the operating environment of a particular pipeline, that leak detection equipment more sensitive than 5 ppm is necessary to meet the ALDP programmatic performance standard at § 192.763(b). For example, an operator may determine that an efficient means of meeting the ALDP performance standard at § 192.763(b) would be to perform leakage surveys by first using very sensitive (in the sub-ppm or low ppb range) vehicle or aircraft mounted sensors, followed thereafter by spot-checks using handheld devices with the minimum sensitivity of 5 ppm proposed at § 192.763(a)(1)(ii). Similarly, an operator may supplement any leak detection equipment meeting the minimum sensitivity requirements proposed at § 192.763(a)(1)(ii) with other techniques for pinpointing leak location (*e.g.,* soap bubble testing) or technologies (*e.g.,* devices for measuring release rate for differentiating between leak grades) for grading identified leaks pursuant to PHMSA's proposed § 192.760.

PHMSA further notes that operators would be able to, pursuant to the proposed § 192.763(c), seek PHMSA review of use of an alternative ALDP performance standard that may entail the use of alternative (including less sensitive) leak detection technology than that proposed under § 192.763(a)(1). This process is available for each of natural gas pipelines (other than distribution pipelines) in Class 1 and 2 locations, and any part 192-regulated pipeline facility transporting flammable, toxic, or corrosive gas other than natural gas.[235] PHMSA acknowledges the fast-evolving state-of-the-art in leak detection technologies for methane and other gases and seeks comments on whether and in what manner it could integrate within a final rule requirements for technologies that may not have specified sensitivities, including continuous pressure wave monitoring, fiber optic sensing, OGI, and LIDAR based detection technologies, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable). PHMSA expects that it would consider the use of such technologies under the § 192.763(c) process or as supplement to other equipment satisfying the minimum sensitivity performance requirements proposed herein.

Apart from minimum sensitivity requirements described above, PHMSA does not propose to require the use of any particular leak detection equipment or technology for every operator or for each type of pipeline. While the PIPES Act of 2020 directs PHMSA to require the use of advanced leak detection technologies and practices, Congress defined this requirement in terms of a performance standard for leak detection and repair programs and described several possible approaches in the statute. PHMSA therefore does not propose to narrowly define advanced leak detection in terms of a particular technology, process, manufacturer, or equipment. One type of technology may not always be appropriate for every flammable, corrosive, or toxic gas, each type of pipeline facility or even across

[234] PPM-meter is a ''path integrated'' summation of measured gas concentration used for open-path devices that sums gas concentration per meter measured up to the effective range in front of the device. Sensitivity may be higher at closer ranges depending on the specific technology used.

[235] Although PHMSA's proposed 5 ppm default performance standard for all part 192-regulated gas pipelines is based principally on commercially available, advanced *methane* leak detection technology for use with natural gas pipelines, PHMSA understands that commercially available, advanced leak detection technology for use with *other* part 192-regulated gas pipeline facilities may (when considered either separately or within a suite of mutually-reinforcing technologies) offer comparable leak detection ability. Further, as explained in the paragraph above, the NPRM contemplates operators of gas pipeline facilities transporting gases other than natural gas (*e.g.,* hydrogen) may request the use of an alternative leak detection performance standard and supporting leak detection equipment.

the range of operational/environmental conditions (*e.g.,* seasonal temperature, humidity, or precipitation patterns) within which a particular pipeline operates. Rather than a technology standard, PHMSA expects each of the periodic evaluation and improvement element of each ALDP (proposed in § 192.763(a)(4)), and the ALDP performance requirement (proposed in § 192.763(b), described later in this section), would encourage operators to continually evaluate and incorporate within their ALDPs such newly commercialized technologies as appropriate for their systems over time. This flexible approach would ensure that operators' leakage detection equipment keeps pace with the state-of-the-art in leak detection technology. Additionally, this NPRM proposes to require operators to select their leak detection equipment based on a documented analysis that considers, at a minimum, the gas being transported, the size, configuration, operating parameters, and operating environment of the operator's system. An operator would be required to choose leak detection technologies that are best able to detect, investigate, and locate all leaks considering these factors. For example, an advanced mobile leak detection system could be an effective tool for detecting methane leaks in a suburban distribution system but may not be optimal for surveying service lines in an area with long setbacks or a transmission pipeline with poor road access. PHMSA also proposes to require operators to analyze, at a minimum, the appropriateness of the following examples of possible advanced leak detection technologies and methods, some of which were referenced in the PIPES Act of 2020: leakage surveys with optical, infrared, or laser-based hand-held devices; continuous monitoring via stationary gas sensors, pressure monitoring, or other means; mobile surveys from vehicle, satellite, or aerial platforms; and systemic use of other technologies capable of detecting and locating leaks consistent with the proposed ALDP performance standard at § 192.763. Operators would be required to maintain records of this analysis for five years. Stationary gas detection systems are already required on compressor stations under PHMSA's existing regulations at § 192.736. Likewise, section 16.4 of the 2001 edition of NFPA 59A,[236] which is incorporated by reference into the federal safety standards for LNG facilities in part 193, requires monitoring of enclosed buildings and other areas that can have the presence of LNG or other hazardous fluid (including natural gas), and specifies flammable gas alarm settings in section 16.4.2. PHMSA invites comments on the value of introducing requirements for continuous monitoring systems, via stationary gas detection systems, pressure monitoring, or other means (including requirements for the use of specific methods or technologies), on other types of pipeline facilities (including whether continuous monitoring would be most appropriate at any particular facilities or locations, or in other particular conditions) within a final rule in this rulemaking proceeding.[237] Comments are especially helpful to PHMSA when they are supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

2. Leak Detection Practices—§ 192.763(a)(2)

The second program element in proposed § 192.763(a)(2) consists of the operator's procedures related to leak detection, investigation, and location. Generally, this would involve supplementing or revising existing procedures in the operator's manual of procedures. At a minimum, the ALDP would include procedures for performing leakage surveys as well as subsequent investigation and location of identified leaks; operator procedures would provide instruction on whether and how each type of leak detection equipment included in the ALDP would be used in performing those tasks. To ensure that operators use procedures appropriate for environmental conditions such as temperature, wind, time of day, precipitation and humidity, the operator must define under which conditions the procedure may and may not be used. Additionally, the procedures must be consistent with any instructions and allowable operating and environmental parameters issued by the leak detection equipment manufacturer to ensure equipment effectiveness. For example, some devices or systems may be unsuitable for use in certain weather or atmospheric conditions, or at certain times of day, or in certain temperatures. As noted in the discussion of leak detection practices in section II.F, establishing and following procedures with parameters appropriate for the leak detection technologies and practices is critical for reliably detecting leaks, especially in challenging conditions. This requirement also addresses the findings from the NTSB's investigation of a 2018 gas explosion involving failed leakage surveys (discussed in section II.H of this NPRM.) due to the operator's improper use of leak detection equipment.[238]

PHMSA proposes to require that an operator's ALDP procedures include investigating and pinpointing the location of all leak indications. For onshore pipelines and offshore pipeline facilities above the waterline, PHMSA proposes in § 192.763(a)(2) to require that pinpointing location be performed using handheld leak detection equipment with a minimum sensitivity of 5 ppm. This proposed requirement would complement PHMSA's proposed ALDP programmatic performance standard in § 192.763(b). If leak location is pinpointed with handheld leak detection equipment during an initial leakage survey, the initial survey would satisfy this requirement. PHMSA proposes that pinpointing leak location on submerged offshore pipelines (including riser piping up to the waterline) would not require the use of leak detection equipment because submerged pipeline leaks are visibly conspicuous.

To ensure the effectiveness of leak detection equipment, PHMSA proposes to require at § 192.763(a)(2)(iii) that an operator have procedures for validating that a leak detection device meets the 5-ppm minimum sensitivity requirement in § 192.763(a)(1)(ii)prior to initial use. This would consist of testing the equipment measurements against a known concentration of gas. Operators would have to maintain records that their leak detection equipment has been validated for five years after the date each device ceases to be used in the operator's ALDP. This is a one-time validation separate from the periodic calibration required under proposed § 192.763(a)(2)(iv) described below. PHMSA also proposes to require that operators have procedures for the maintenance and calibration of leak detection equipment—including at least

[236] NFPA, *NFPA–59A: Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)—2001 Edition* (2001).

[237] To the extent that a comment proposes to require installation of such technologies on a pipeline, PHMSA also solicits comment on the potential application of PHMSA's statutory prohibition on retroactive design and installation standards. *See* 49 U.S.C. 60104(b).

[238] National Transportation Safety Board. ''Pipeline Accident Report: Atmos Energy Corporation Natural Gas-Fueled Explosion: Dallas, Texas: February 23, 2018.'' NTSB/PAR–21/01. Jan. 12, 2021. Washington, DC *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR2101.pdf.*

any maintenance and calibration procedures recommended by the equipment manufacturer—to ensure that equipment is functioning as intended throughout its service life. Finally, PHMSA proposes to require that operators recalibrate leak detection equipment following an indication of malfunction.

3. Leakage Survey Frequency—§ 192.763(a)(3)

The third element that PHMSA proposes to require of an ALDP is the frequency of leakage surveys, which is specified in proposed § 192.763(a)(3). Minimum leakage survey frequencies are defined in § 192.723 for gas distribution pipelines and in § 192.706 for gas transmission, offshore gathering, and Types A, B, and C gathering pipelines. As noted in section IV.A, less sensitive survey equipment may require more frequent surveys in order to provide an equivalent degree of leak or emissions detection.[239] If more frequent leakage surveys are necessary to reliably meet the ALDP programmatic performance standard in proposed § 192.763(b), or as otherwise specified by the operator, that must be noted in the operator's ALDP. For example, more frequent leakage surveys may be appropriate for less sensitive leak detection equipment authorized for use pursuant to proposed § 192.763(c), challenging survey conditions, or facilities known to leak based on their material, design, or past operating and maintenance history. As noted above in section IV.B.1, PHMSA invites comments on the value of requiring continuous monitoring systems on these types of facilities or any other pipeline facilities (for potential inclusion within a final rule in this proceeding). Comments are especially helpful to PHMSA when they are supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

4. Program Evaluation and Improvement—§ 192.763(a)(4)

The fourth and final element of an ALDP in § 192.763(a)(4) is program evaluation and improvement. At least annually, operators would have to re-evaluate the elements of their ALDPs considering, at a minimum, the performance of the leak detection equipment used, the adequacy of their leakage survey procedures, advances in leak detection technologies and practices, the number of leaks initially detected by third parties, the number of leaks and incidents on the pipeline, and estimated emissions from detected leaks. This proposal is similar in principle to the existing continuous improvement requirements under IM requirements in part 192, subparts O and P, as well as requirements for certain operators to periodically review procedures under § 192.605(b)(8) and (c)(4). PHMSA expects this proposal would ensure operators periodically evaluate ways to improve their leak detection programs based on leak detection performance data and advances in technology. For example, if an operator finds evidence that their ALDP fails to detect leaks during leakage surveys, or that it is finding grade 1 or 2 leaks but does not find any grade 3 leaks, changes to program elements may be necessary to ensure that the minimum performance standard in § 192.763(b) described below is met. This provision would offer potential environmental benefits and could also result in cost-savings to operators and shippers, by helping further reduce product losses from pipeline facilities.

5. Advanced Leak Detection Performance Standard—§ 192.763(b)

The ultimate benchmark for the effectiveness of an operator's ALDP would be a holistic, program-wide performance standard at § 192.763(b). Specifically, PHMSA proposes to require that an ALDP must be capable of detecting all leaks that produce a reading of 5 ppm or greater of gas when measured from a distance of 5 feet from the pipeline, or within a wall-to-wall paved area. As described in the discussion of leak detection equipment above, the proposed 5 PPM standard represents a protective, detection threshold achievable using mainstream, commercially available, advanced leak detection equipment. The § 192.763(b) ALDP performance standard is consistent with that minimum sensitivity for leak detection equipment, but it focuses on the characteristics of the leak (in particular, whether the leak rate or operating environment results in a reading of 5 ppm) rather than on the sensitivity of the leak detection equipment employed by an operator. For example, a walking survey conducted alongside a pipeline with thorough, careful, procedures to ensure detection of all leaks could achieve this standard with an FID or other handheld device with the 5 ppm sensitivity required by § 192.763(a). But mobile leak detection systems and aerial systems that use gas samplers or other sensors to detect leaks at a greater distance may allow for more efficient leakage surveying, but could require more sensitive (sensors in the ppb range) leak detection equipment coupled with advanced analytics (followed by the use of handheld leak detection equipment to pinpoint leak location) to detect and locate the same leak. Similarly, leakage surveys employing human or animal senses would have to employ leak detection equipment to investigate and pinpoint the location of any leaks detected during those non-instrumented surveys.

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.[240] However, as discussed above in section II.D.4, most currently available methane leak detection technologies are focused on calculating the concentration of gas in the air rather than leak flow rate. Moreover, PHMSA's choice of leak concentration-based performance standard for leak detection equipment was informed by the goal of (as much as possible) identifying a single performance standard that would be well-suited for leak detection on both aboveground and buried natural gas pipelines. Additionally, consistent with the GPTC Guide grading criteria and as acknowledged in the comments of AGA et al. to the 2021 Public Meeting, a concentration-based metric is especially useful for addressing explosion risks to public safety (regardless of a leak's flow rate). To the extent that operators find that leak rate measurements are helpful for identifying or grading leaks or in calculating estimated emissions consistent with changes to part 191 reporting requirements discussed elsewhere in this NPRM, operators may incorporate leak flow rate metrics within their ALDPs to supplement leak concentration metrics used in PHMSA's proposed leak detection and ALDP performance standard. In particular, leak rate measurements may help operators quickly grade certain leaks as grade 2 leaks based on a leak rate in excess of 10 CFH. Based on available

[239] Ravikumar, Arvind Ph.D. ''FEAST-Based Evaluation of Methane Leak Detection and Repair Programs Using New Technologies.'' EPA Methane Detection Technology Workshop (August 24, 2021). *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop.* Day 2 at 1:33:50.

[240] Written comments submitted before and after the meeting are available in the rulemaking docket at Doc. No. PHMSA–2021–0039. While some commenters observed that a leak flow rate performance standard would be desirable, no commenter provided a suggestion for how this could be implemented.

information, PHMSA's current assessment is that the proposed § 192.763(b) ALDP performance standard represents a threshold of detection demanding enough to ensure that operator ALDPs are capable of detecting nearly all leaks on gas gathering, transmission, and distribution pipelines. That said, PHMSA invites comment on whether and how an alternative ALDP performance standard—such as a more demanding volumetric standard, or a flowrate-based standard—should be adopted in the final rule. Proposed alternatives are most helpful when they are supported by a discussion of their value for public safety and environmental protection, as well as their technical feasibility, cost-effectiveness, and practicability.

6. Alternative Advanced Leak Detection Performance Standard—§ 192.763(c)

Lastly, because of the comparatively low emissions from natural gas transmission pipeline leaks (relative to other gas transmission pipeline facilities such as compressor stations),[241] comparatively lower potential safety risks to persons or property in remote areas, and the continued development of methane leak detection technologies, PHMSA proposes, at § 192.763(c), to allow operators of each of gas transmission, offshore gathering, and Types A, B, and C gathering pipelines, located in Class 1 or 2 locations and outside of HCAs to request an alternative ALDP performance standard (and use of supporting leak detection equipment) pursuant to the notification and PHMSA review procedures established in § 192.18. PHMSA similarly proposes that operators of any species of part 192-regulated gas pipelines transporting flammable, toxic, or corrosive gases other than natural gas may request use of an alternative ALDP performance standard (and use of supporting leak detection equipment).

The operator must demonstrate, in the notification, that the alternative performance standard is consistent with pipeline safety and equivalent to the performance standard in § 192.763(b) with respect to reducing greenhouse gas emissions and other environmental hazards. This flexibility can promote emerging technologies where they may be most effective. For example, some aerial survey methods may not yet be able to detect small but potentially hazardous, below-ground methane leaks from a distribution pipeline system, but they could be an efficient leakage survey method for leaks on below-ground onshore gas transmission lines, which leaks are larger on average due to the higher operating pressure. Similarly, an alternative performance standard may be appropriate for flammable, toxic, or corrosive gases for which commercially available, advanced leak detection technology either uses different units of measure than that provided for in § 192.763(a) or is less sensitive than the default 5 ppm performance standard. PHMSA proposes to require that notifications submitted under this provision must include information about—among other things—the location and material properties of the pipeline facility, the gas being transported, a description of the proposed alternative performance standard, and a description of the ALDP equipment and procedures that would be used.

C. Leak Grading and Repair—§§ 192.703, 192.760, and 192.769

As discussed in section II, gas pipeline operator leak grading and repair practices are currently insufficient to meet the threats to the environment and public safety from leaks on their systems. Current requirements lack meaningful requirements for timely grading and repair of leaks; only leaks that are ''hazardous'' (a term that is undefined) are subject to explicit repair timelines and requirements, and PHMSA's IM regulations in subparts O (transmission) and P (distribution) largely defer to operator discretion regarding leak repair efforts for the small portion of gas pipelines subject to those requirements. Only a handful of States have imposed their own, more demanding leak repair requirements than PHMSA's. Similarly, while some operators have voluntarily adopted their own leak grading and repair practices, many operators have no such requirements, and those that do may not apply these requirements consistently across different types of pipeline facilities.

PHMSA therefore proposes to address these regulatory gaps by establishing requirements at §§ 192.703, 192.760, and 192.769 for all part 192-regulated gas pipeline operators to ensure properly-trained personnel grade and repair all leaks pursuant to a schedule for each grade based on the severity of public safety and environmental risks.[242] PHMSA's proposal includes a leak grading framework informed by the criteria of the GPTC Guide—which is familiar to industry and State enforcement personnel—to facilitate compliance and regulatory oversight. PHMSA's proposed leak grading framework in § 192.760 would require the classification of every leak on any portion of a gas pipeline (including components such as flanges, meters, regulators, and ILI launchers and receivers) as either (in order of decreasing priority) grade 1, grade 2, or grade 3 based on the magnitude and probability of risks posed by that leak to the public and the environment, prioritizing remediation of leaks presenting the most serious hazards to people or the environment and setting minimum repair timelines for each grade. Operators would be obliged to investigate each leak discovered on their pipelines immediately and continuously until a leak grade determination has been made to ensure that risks to public safety and the environment from each leak are diligently evaluated and repairs scheduled as appropriate to remedy any risks. The NPRM also includes a number of enhancements to the GPTC Guide's three-tiered framework to address gaps in safety and environmental protection, including establishment of repair deadlines for grade 3 leaks and incentivizing replacement or remediation of pipe known to leak. Operator personnel engaged in leakage survey, investigation for grading purposes, and repair would be subject to baseline training requirements. Lastly, PHMSA has proposed revision of the documentation requirements at § 192.605, consistent with statutory language in section 114 of the PIPES Act of 2020, to oblige operators of gas transmission, distribution, offshore gathering, and Types A, B, and C gathering pipelines to update their procedures to provide for the replacement or remediation of pipelines known to leak.

PHMSA expects each of the proposed leak grading and repair requirements discussed in this section IV.C would be reasonable, technically feasible, cost-effective, and practicable for affected gas pipeline operators. As explained above, some operators that would be subject to this NPRM's proposed requirements have one or more pipelines within their systems that are already subject to some leak repair (either prescriptive or integrity management-based) requirements under PHMSA or State regulatory regimes. Other operators may voluntarily exceed minimum regulatory

[241] See the discussion of GHGI data in section II.E. of this NPRM.

[242] These grading requirements apply to all commodities transported under part 192, including petroleum gas, as all non-natural gas commodities covered under part 192 are hazardous to human health or the environment. *See* § 192.3 (definition of gas). Petroleum gas systems are subject to some specialized grading criteria due to the unique hazards posed by this heavier-than-air gas.

requirements given the significant public safety and environmental risks posed by releases of pressurized (natural, flammable, toxic, or corrosive) gas from their pipelines, or to minimize loss of commercially valuable commodity. PHMSA's proposal builds on those existing practices by establishing for part 192-regulated gas pipelines a common leak repair obligation leveraging the GPTC Guide's familiar framework for classifying *all* leaks—not merely those thought to pose imminent risks to public safety. PHMSA in turn calibrated its proposed repair timelines for each leak grade based on the magnitude of public safety and environmental risks; within those default repair timelines, operators may be able to seek extensions or (with respect to compressor stations) be relieved of obligations from potential overlapping requirements from certain methane emissions requirements imposed by other Federal and State regulatory authorities. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the NPRM's proposed compliance timelines—which are based on an effective date of six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite leak grading and repair protocols (including, but not limited to, those pertaining to procedure development, post-repair inspection, and recordkeeping) and manage any related compliance costs.

1. Leak Repair Requirement—§ 192.703(c)

Consistent with the proposed new leak grading and repair requirements at § 192.760(c) discussed below, PHMSA proposes to eliminate the current limitation of operators' repair obligation to leaks that are ''hazardous'' to public safety. To accomplish this, PHMSA proposes to revise § 192.703(c) to require grading and repair criteria for *all* detected leaks. Additionally, PHMSA proposes that its expanded leak repair obligations would attach to all part-192 regulated gas pipelines because any leak from those pipelines entails risks to one or both of public safety and the environment. While any leak of methane from a gas pipeline system necessarily entails environmental harm proportional to the amount of methane released to the atmosphere, PHMSA proposes introducing minimum sensitivity standards for leak detection equipment at § 192.763 (discussed below) in recognition that some leaks are so small that the harm they present does not warrant expending the resources necessary to detect and repair them, particularly where the leak is approaching the limits of detection with commercially available advanced technologies. This approach is consistent with Congress's direction in the PIPES Act of 2020 for PHMSA to require that operators repair or replace ''each leaking pipe, except a pipe with a leak so small that it poses no potential hazard.'' Under the proposed approach, some very small leaks which would escape detection would not qualify as a ''leak or hazardous leak'' under § 192.3, and thus would not be repaired.

2. Replacement of Pipelines Known to Leak—§ 192.605

Among the self-executing mandates within section 114 of the PIPES Act of 2020 is a requirement that pipeline operators update their procedures to provide for minimizing releases of natural gas; eliminating hazardous leaks of natural gas and any other flammable, toxic, or corrosive gas; and the replacement or remediation of pipelines known to leak based on their material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history. PHMSA proposes to incorporate that self-executing statutory language within § 192.605's list of prescribed content for the operations, maintenance, and emergency procedures of gas transmission, distribution, offshore gathering, and Types A, B, and C gathering pipelines. Affected operators may implement this proposed regulatory amendment by updating (to the extent they have not done so already in complying with the self-executing statutory mandate) their operating, maintenance, and emergency procedures to contain protocols guiding decision-making on whether replacement or remediation of a particular pipeline or its components would be a more durable and effective solution for remediating or preventing leaks that entail public safety and the environmental harms. PHMSA submits that operator protocols could (in addition to referencing the leak-prone materials identified in section 114 language) reference authoritative resources (*e.g.,* State pipeline safety regulatory actions, PHMSA pipeline failure investigation reports and advisory bulletins, NTSB findings, or industry efforts) to assist in identifying pipelines known to leak and evaluating whether replacement or remediation would be more appropriate in each case, as discussed in the context of distribution pipeline leakage surveys in section IV.A.1. PHMSA invites comment on the value of either explicitly listing leak-prone materials (either within part 192 or within periodically-issued implementing guidance). Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

PHMSA's proposed revision to § 192.605 addressing replacement of pipelines known to leak would apply only to gas transmission, distribution, and part 192-regulated gathering lines which are subject to the self-executing statutory mandate. The more general requirement from section 114 of the PIPES Act to have procedures addressing minimizing releases of natural gas are proposed for part 192-regulated gas pipeline facilities in § 192.605, UNGSFs in § 192.12, and LNG facilities in §§ 193.2503 and 193.2605. That proposal is discussed in section IV.F. PHMSA solicits comment regarding whether any final rule in this rulemaking proceeding should extend the proposed revision addressing replacement of pipelines known to leak to gas pipeline facilities other than piping systems (in particular, part 193 LNG facilities and UNGSFs). Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

3. Compressor Stations—§ 192.703(d)

As described in section II.B of this NPRM, EPA has imposed methane emissions standards at 40 CFR part 60 for the oil and gas industry establishing fugitive emissions monitoring and repair requirements for gas transmission compressor stations and gas gathering boosting stations constructed, reconstructed, or modified after September 18, 2015 (subpart OOOOa). EPA has also proposed (1) a new 40 CFR part 60, subpart OOOOb that would update standards for gas transmission compressor stations and gas gathering boosting stations installed, reconstructed or modified after November 15, 2021, and (2) nationwide emissions guidelines that would be located at 40 CFR part 60, subpart OOOOc addressing methane emissions from oil and gas existing sources including fugitive emission components at existing gas transmission compression stations and gas gathering boosting stations that would not be subject to its proposed 40 CFR part 60, subpart OOOOb standards.[243]

Given EPA's existing and proposed robust methane emissions standards, PHMSA proposes a narrow exception from some of the proposed requirements for gas transmission and gas gathering compressor stations that would already be subject to monitoring and repair requirements within EPA's current 40 CFR part 60, subpart OOOOa regulations, proposed subpart OOOOb updates and subpart OOOOc methane emissions guidelines (as implemented through EPA-approved State plans with standards at least as stringent as EPA's emission guidelines in subpart OOOOc or implemented through a Federal plan).[244] Specifically, PHMSA proposes exception from each of its requirements pertaining to leak repair (§ 192.703(c)), leakage survey and patrol (§§ 192.705 and 192.706), leak grading and repair (§ 192.760), ALDPs (§ 192.763) and qualification of leak detection personnel (§ 192.769). Operators would, notwithstanding the exception from other elements of § 192.760, remain obliged to retain records associated with leak repairs pursuant to § 192.760(i) to ensure appropriate documentation of change and trend analysis on those facilities, as well as adequate documentation to support regulatory oversight activity by pertinent State and Federal regulatory authorities. To establish clear boundaries for the exception, PHMSA proposes that the exception would cover those components located within the first block valve entering or exiting the facility (exclusive of that block valve)—which valves mark the boundary of station overpressure protection pursuant to § 192.167.

EPA's proposed regime at 40 CFR part 60 for monitoring fugitive methane emissions from gas transmission compression stations and gas gathering boosting stations provides public safety and environmental protection comparable to PHMSA's proposals in this NPRM.[245] EPA regulations at 40 CFR 60.5397a(g)(2) within subpart OOOOa require quarterly[246] methane emissions monitoring surveys of leaks from all gas transmission compression and gas gathering boosting systems—more frequent than PHMSA's proposed leakage survey revisions for all but those facilities in HCAs within Class 4 locations. EPA requirements require those surveys be performed using leak detection equipment—either optical gas imaging or another ''instrument'' (such as FID) with sensitivity of at least 500 ppm that complies with method DA in appendix A–7 to 40 CFR part 60—standards that are similar to the leak detection equipment contemplated by this NPRM. EPA regulations require an operator first attempt repair of any fugitive emissions so detected within 30 days and complete repairs within 30 days of that first attempt—equivalent to the 30-day repair timeline for grade 2 gas transmission pipeline leaks in HCAs and class 3 and class 4 locations proposed in this NPRM but more aggressive than the proposed 6-month timeline for repair of grade 2 leaks in non-HCA class 1 and class 2 locations. And although the EPA's repair timelines may be less demanding than those proposed in this NPRM for grade 1 leaks, PHMSA understands that EPA's more frequent required surveys would ensure timely detection and remediation of leaks on gas transmission compression stations and gas gathering boosting stations. Further, allowing operators to direct compliance efforts toward EPA's regulatory regime rather than proposing additional requirements for EPA-regulated facilities ensures that operator resources are focused on methane emissions reduction rather than overlapping compliance frameworks.

In the event that EPA's proposed regulations at subparts OOOOb and OOOOc are not in effect because they have not yet been finalized or for any other reason, the proposed exception would not apply and the leak detection, grading, and repair requirements proposed herein would apply to gas transmission and gas gathering compressor station facilities.

PHMSA invites comment on the appropriateness of this proposed exception and the specific regulatory requirements within its proposed scope (to include comments regarding any potential regulatory gaps that may arise from this exception) for consideration in any final rule in this proceeding. Should stakeholders submit proposed alternatives content for this exception, those alternatives would be most helpful if they are supported by evaluation of the safety or environmental benefits, technical feasibility, cost-effectiveness, and practicability.

4. Grade 1 Leaks—§ 192.760(b)

A grade 1 leak is the highest priority grade and represents an existing or probable hazard to persons, property, or an existing, grave hazard to the environment. A grade 1 leak is an urgent or emergency situation—for this reason, PHMSA proposes that operators must be required to take ''immediate and continuous'' action to eliminate the hazards to public safety and the environment. As soon as an operator determines a grade 1 leak exists, it must immediately dispatch personnel to address hazards to people or the environment and undertake other actions (including, but not limited to, those identified at proposed § 192.760(a)(2), most of which track requirements elsewhere in PHMSA regulations) to minimize risks to public safety and the environment. The appropriate ''immediate and continuous action[s]'' taken by an operator would necessarily depend on the nature of the leak and pipeline operational and environmental conditions. For example, the ''immediate and continuous action[s]'' required of the operator of a submerged, offshore pipeline in responding to a grade 1 leak on its system may entail different engineering actions or considerations than an operator of an onshore, non-buried, low-pressure pipeline with a grade 1 leak.

[243] *See* EPA SNPRM.

[244] Gas pipeline facilities that would be subject to this proposed exception would remain PHMSA-jurisdictional gas pipeline facilities otherwise subject to parts 191 and 192 requirements and PHMSA regulatory oversight.

[245] EPA's updated methane emissions new source performance standards in its proposed 40 CFR part 60, subpart OOOOb (new sources) and accompanying methane emissions guidelines at subpart OOOOc (existing sources) are not yet final; however, PHMSA considers the monitoring and repair elements of those proposals to be at least as protective of public safety and the environment as corresponding existing requirements 40 CFR part 60, subpart OOOOa. However, should proposed subparts OOOOb and OOOOc not be finalized, only gas transmission compression and gas gathering boosting stations subject to 40 CFR part 60, subpart OOOOa would be eligible for the exception proposed in this NPRM.

[246] While the final rule titled ''Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources Review'' (85 FR 57018 (Sept. 14, 2020)) removed all methane standards from 40 CFR part 60, subpart OOOOa, including the quarterly monitoring and repair requirements for methane fugitive emissions at compressor stations at 40 CFR 60.5397a(g)(2), Congress subsequently disapproved that final rule by a joint resolution (Pub. L. 117–23) enacted pursuant to the Congressional Review Act (Pub. L. 104–121). The president signed that joint resolution into law. As a result, the EPA's September 2020 final rule is treated as if it had never taken effect, and the methane standards in subpart OOOOa promogulated in 2016 remain in effect. *See* EPA's Q&A for more information. *https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf.*

PHMSA's proposed grade 1 leak criteria elaborate that, at a minimum,[247] a grade 1 leak includes any of the following characteristics:

- Any leak that, in the judgment of operating personnel at the scene, is of sufficient magnitude to be an existing or probable hazard to persons or property, or a grave hazard to the environment;
- Any amount of escaping gas that has ignited;
- Any indication that gas has migrated into a building, under a building, or into a tunnel;
- Any reading of gas at the outside wall of a building, or areas where gas is likely to migrate to an outside wall of a building;
- Any reading of 80% or greater of the LEL in a confined space; [248]
- Any reading of 80% or greater of the LEL in a substructure (including gas associated substructures of a gas pipeline or non-associated gas pipelines), from which gas would likely migrate to the outside wall of a building;
- Any leak that can be seen, heard, or felt by human senses; or
- Any leak reportable as an incident as defined in § 191.3.

PHMSA's proposed grade 1 leak criteria resemble those in the GPTC Guide and, consistent with that framework, are intended to prioritize for immediate repair those leaks that pose a significant hazard to people and property. However, PHMSA proposes important differences designed to address gaps in safety and environmental protection. First, PHMSA proposes to characterize a grade 1 leak to include leaks with grave environmental harms. Including such leaks in the grade 1 leak criteria is consistent with the mandate for this NPRM in section 113 of the PIPES Act of 2020 and would reduce public safety risks. Any leak of methane from a gas pipeline system necessarily entails environmental harm proportional to the total release volume by contributing to climate change. PHMSA's proposed language therefore distinguishes between public safety risks (which can be *existing* or *contingent* under the historical GPTC Guide framework) and the *certain* environmental harms from leaks of methane and other gas. PHMSA proposes grade 1 criteria scaled language (''*grave* hazard to the environment'') to acknowledge the magnitude of that harm from methane or other gas released from leaks can vary from one leak to the next. A leak satisfying one or more of its proposed grade 1 criteria would be a release of gas involving a risk of ignition that is sufficient to be an existing or probable future hazard to public safety, or release of sufficient volume that poses a grave hazard to the environment.

Proposed § 192.760(b)(1)(vi) also classifies as a grade 1 leak any reading of 80% LEL or greater in a substructure (subterranean structures too small for a human to enter) from which gas would likely migrate to the outside wall of a building. Unlike the GPTC Guide, the proposed criteria would include substructures associated with the operator's gas pipeline. A gas-associated substructure includes facilities such as small valve boxes and other vaults not intended for human entry. While it is not unusual for some gas to accumulate in gas-associated substructure, a potentially explosive concentration of gas with the potential to migrate to nearby buildings is an immediate public safety hazard regardless of whether a substructure is associated with a gas pipeline or not. PHMSA also proposes conforming revisions to § 192.3 to introduce definitions for the terms ''substructure,'' gas-associated substructure,'' and ''confined space'' to facilitate operator compliance and PHMSA and State regulatory oversight.

Proposed § 192.760(b)(1)(vii) would classify any leak that can be seen, heard, or felt as a grade 1 leak. In comparison, Table (3a) in the GPTC Guide limits this criterion to leaks that are in a location that may endanger the public or property. Applying the seen, heard, or felt criteria to leaks regardless of location ensures operator field personnel have a standard for classifying leaks that potentially cause significant environmental or safety consequences in the form of methane emissions and other pollutants. The visible indications of a gas leak may include for example, ground disturbances, a jet or vapor cloud of condensation, or blowing debris. A gas leak can also emit a hissing sound or, for larger leaks, sounds resembling a jet engine or train. Tactile indications of a leak include force from a jet of gas or vibrations in the pipe or soil. Each of these physical markers of a pipeline leak are typically more apparent on higher-pressure, larger volume leaks. PHMSA does not consider impacts to vegetation to be a definitive indication of a grade 1 leak for these purposes. However, an operator should consider if there are severe or widespread impacts to vegetation during a leakage investigation. Additionally, a leak on an offshore pipeline that is visible from the surface (*i.e.,* bubbles or condensate sheen) would be classified as a grade 1 leak under this criterion.

Lastly, PHMSA proposes that any leak reportable as an incident under part 191 would be classified as a grade 1 leak. The definition of ''incident'' in § 191.3 would include any event involving the release of gas from a pipeline that results in one or more of the following consequences:

- A death or personal injury necessitating in-patient hospitalization;
- Estimated property damage of $129,300, excluding the cost of lost gas, (adjusted for inflation for calendar year 2022); or
- Unintentional estimated gas release of 3 MMCF or more.

This criterion would address gaps in the GPTC Guide's current grade 1 leak criteria and would help ensure the repair of leaks that involve very large release volumes, or which are known to result in significant public safety and environmental harms. Further, if a previously detected leak later results in an incident causing significant safety and environmental consequences, then it almost certainly would have been an ''existing or probable hazard'' to persons and the environment at the time of detection and should have been graded and repaired accordingly. PHMSA invites comments on other potential criteria for identifying grade 1 leaks subject to immediate repair (for potential inclusion within a final rule in this proceeding), including the utility of adopting a quantified emissions rate criteria for grade 1 leaks or other characteristics indicative of a grave environmental hazard, in addition to criteria proposed above. Comments are especially helpful to PHMSA when they identify a specific quantified emissions rate threshold or other specific characteristics supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

[247] Operators may decide to adopt additional grade 1 criteria (or, for that matter, grade 2 criteria) supplementing the baseline criteria PHMSA proposes herein.

[248] Several of the grading criteria reference gas readings and are expressed as percent of the lower explosive limit (LEL). The LEL is the minimum required concentration of gas necessary for the gas to ignite when exposed to an ignition source. Percent LEL measures how close measured gas concentration is to reaching a flammable atmosphere. The LEL of natural gas is 5% gas by volume. However, the LELs for other flammable gases vary (*e.g.,* the LEL for hydrogen gas is 4% gas by volume). A reading of 100% or more of LEL indicates that a flammable atmosphere is present, provided there is a sufficient concentration of oxygen present to support combustion and the upper explosive limit (UEL) is not reached. The percent LEL is typically measured during a leak investigation with a combustible gas indicator.

5. Grade 2 Leaks—§ 192.760(c)

PHMSA also proposes to modify the GPTC Guide's characterization of grade 2 leaks to introduce a reference to environmental harms from those leaks: a grade 2 leak would be a leak which presents a probable future hazard to public safety or a significant hazard to the environment. PHMSA intends the proposed characterization of grade 2 leaks to include those leaks that are not as urgent a hazard to either public safety or the environment as a grade 1 leak that it would require immediate and continuous action to eliminate the hazard, but which are significant enough to warrant timely repair.

PHMSA proposes to classify a grade 2 leak as any leak (other than a grade 1 leak) with any of the following characteristics:

- A reading of 40% or greater of the LEL under a sidewalk in a wall-to-wall paved area that does not qualify as a grade 1 leak;
- A reading of 100% of the LEL under a street in a wall-to-wall paved area that does not qualify as a grade 1 leak;
- A reading between 20% and 80% of the LEL in a confined space;
- A reading less than 80% of the LEL in a substructure (other than gas associated substructures) from which gas could migrate;
- A reading of 80% or greater of the LEL in a gas associated substructure from which gas is not likely to migrate;
- Any reading greater than 0% gas on a transmission or Types A or C gas gathering pipeline that does not qualify as a grade 1 leak;
- Any leak with a leakage rate of 10 CFH or more that does not qualify as a grade 1 leak;
- Any leak of LPG or hydrogen that does not qualify as a grade 1 leak; or
- Any leak that, in the judgment of operator personnel at the scene, is of sufficient magnitude to justify scheduled repair within 6 months or less.

The proposal has important differences from the GPTC Guide that are designed to address gaps in safety and environmental protection. Specifically, PHMSA proposes to delete qualifying language in grade 2 criteria to minimize ambiguity and ensure enforceability of the proposed repair standards. For illustration, in example A.B.2. in Table 3b of the GPTC Guide, any reading of 100% LEL or greater under a street in a wall-to-wall paved area ''that has significant gas migration'' that is not a grade 1 is considered a grade 2 leak, however what constitutes ''significant'' gas migration is not defined or straightforward to enforce. Instead, the NPRM proposes to apply this standard to any such concentration of gas, which is itself hazardous to public safety or the environment, with any migration. Similarly, PHMSA does not propose to condition criteria for grade 2 leaks in substructure on the likelihood that ''gas would likely migrate creating a probable future hazard'' since a concentration of 80% or more of LEL, near the explosive limit, within a substructure is itself a probable future hazard to public safety. Additionally, PHMSA proposes to add a new criterion for all leaks from LPG systems that do not qualify as a grade 1 leak, consistent with an observation in the GPTC Guide that since LPG is heavier than air and does not dissipate like natural gas, ''few [LPG] leaks can safely be classified as Grade 3.'' [249] Likewise, PHMSA proposes that Grade 2 is the minimum priority grade for leaks of gaseous hydrogen. PHMSA understands these heightened safety requirements (compared to natural gas pipelines) are warranted because hydrogen is itself a flammable gas with a lower explosive limit and lower autoignition temperature than methane. And research summarized by the National Renewable Energy Laboratory indicates that overpressure blast risk in enclosed spaces and increases with the proportion of hydrogen within hydrogen/natural gas blends (particularly for concentrations above 50% hydrogen) and that, for transmission line ruptures, fatal injury risk increases as either proximity to the pipeline or the share of hydrogen in a natural gas blend increases.[250]

PHMSA also proposes to include a new emissions rate criterion for grade 2 leaks: any leak with an emissions rate equal to or greater than 10 CFH would need to be classified as a grade 2 leak. PHMSA expects this criterion would ensure prioritized repair of such environmentally damaging leaks even if other grade 1 or grade 2 criteria are not met. PHMSA further notes that this proposed 10 CFH criterion is the same criterion used by PG&E's Super Emitter Program, which was based on data showing that methane leaks larger than 10 CFH represented only 2% of all leaks by number but over half of all emission volumes on PG&E's gas distribution system.[251] PHMSA's selection of a 10 CFH emissions rate is consistent with the AGA et al. assertion that a significant share of emissions from natural gas pipeline systems can be caused by a relatively small proportion of leaks within each leak category.[252] A 2016 analysis by Brandt, et.al., of 15,000 emissions measurements from prior studies found that 5% of releases contributed to over half of total emissions volumes.[253] An emissions rate of 10 CFH correlates to emissions of ca. 87,600 ft^3 of methane (roughly 1,600 kg of methane) if left unrepaired for a year.[254]

PHMSA considered alternative approaches to its proposed emissions rate criterion but is concerned about their practicability. PHMSA invites comment on appropriate, alternative grade 2 emissions rate criterion thresholds and calculation methodologies—particularly considering the extent to which emissions from below ground leaks could be incorporated. PHMSA considered an approach employed by the Commonwealth of Massachusetts which categorizes methane leaks from natural gas pipelines as ''environmentally significant'' grade 3 leaks if they have a barhole reading of 50% gas in air or higher, or a measured leak migration extent of 2,000 square feet or greater.[255] In Massachusetts, leaks with a migration extent from 2,000 to 10,000 square feet must be repaired within 2 years and leaks with a migration extent greater than 10,000 square feet must be repaired within 12 months. This method—which measures the extent of below-ground migration as a proxy for the release rate—could be a relatively straightforward means to classify large-volume, below-ground leaks (particularly for gas distribution systems). However, since gas migration can be affected greatly by soil and weather conditions, the 2,000 square feet element of this approach may not be

[249] See Table 3 C in Appendix G–192–11A of the GPTC Guide.

[250] Melania, et al., National Renewable Energy Laboratory Technical Report TP–5600–51995, ''Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues'' at 16–17 (Mar. 2013), *https://www.nrel.gov/docs/fy13osti/51995.pdf.*

[251] Rongere, Francois. ''Lessons Learned from the First Year of the Super Emitter Program.'' PG&E Nov. 5, 2019. *https://www.epa.gov/sites/default/files/2019-12/documents/lessonslearnedfirstyearsuperemitterprogram_francoisrongere.pdf;* Lamb, Brian K., et al. ''Direct Measurements Show DECREASING Methane Emissions from Natural Gas Local Distribution Systems in the United States.'' *Environmental Science & Technology,* vol. 49, no. 8, 2015, pp. 5161–5169., doi:10.1021/es505116p.

[252] AGA et al. at 5.

[253] Brandt AR, Heath GA, Cooley D. Methane Leaks from Natural Gas Systems Follow Extreme Distributions. Environ Sci Technol. 2016 Nov 15;50(22):12512–12520. Doi: 10.1021/acs.est.6b04303. Epub 2016 Oct 26. PMID: 27740745.

[254] The value here was calculated assuming a density of methane of 0.01926 kg/ft^3.

[255] 220 CMR 114.07(1)(a).

appropriate for a nationwide standard applicable to natural gas distribution, gathering and transmission pipelines across a diversity of operational and environmental conditions, as well as other gases transported in part 192-regulated gas pipelines. Variations in gas migration due to operational and site-specific environmental considerations may then result in missing or over-stating large-volume leaks. PHMSA also considered a relative emissions criterion, such as requiring an operator to repair leaks with an emissions quantity larger than the median leak rate on the operator's system by release rate (estimated with an advanced mobile leak detection technology, high-flow sampler, or equivalent method) or measured gas concentration. While that approach would be comparatively simple to implement, it could result in inconsistent repair requirements across operators as well as perverse consequences: an operator with a well-designed and maintained system with few large-volume leaks would have the same proportion of priority repairs as an operator with poor maintenance practices or significant mileage of leak-prone pipe such that the latter operator could defer repair of potentially large leaks.

PHMSA invites comments on the proposed criteria for identifying grade 2 leaks that constitute a significant hazard to the environment, including the practicability of using a specified emissions rate criterion (and whether 10 CFH is the appropriate emissions rate for grade 2 leaks), for potential inclusion within a final rule in this proceeding. Comments on this question are especially helpful if they identify a specific emissions rate, gas concentration, or other measurement supported by research or operational experience for identifying leaks that should be subject to shorter repair timelines due to their potential environmental impacts over time. PHMSA further invites comments on how quantification of emissions rates are or could be integrated into operator's leak survey, investigation, and management procedures. Finally, PHMSA seeks comments on whether other criteria could be used to identify leaks with significant environmental harm. Comments on these questions are especially helpful to PHMSA when they identify the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

PHMSA also proposes a minimum grade 2 classification for any leak on a gas transmission or Type A or C gathering pipeline. The GPTC Guide identifies leaks on pipelines operating at 30% SMYS or greater (*i.e.,* most gas transmission lines) in Class 3 or Class 4 locations, other than grade 1 leaks, as grade 2 leaks and assigns a six-month repair requirement. This NPRM proposes to apply this repair timeline to all gas transmission pipelines, and Types A and C gathering pipelines because of the similar design and operating characteristics—and therefore public safety and environmental risk profiles—of those pipelines. In particular, transmission and Type A and Type C gathering lines operate at a high stress level and therefore, as described in section II.D.3, there is a correspondingly higher risk of a rupture if the condition that caused the leak deteriorates further. PHMSA does not propose a similar requirement for offshore gas gathering pipelines because many of those pipelines operate far from the general public and at lower pressures than gas transmission and Type A gathering pipelines such that their public safety and environmental risks are distinguishable.

PHMSA also proposes more timely repair of grade 2 leaks than contemplated by the GPTC Guide, which requires operators to repair such leaks within 12 months of detection. Specifically, PHMSA proposes a default requirement for grade 2 leak repairs to be completed within the earlier of six months of detection, or the repair timeline specified in the operator's procedures or IM plan. The accelerated default repair timeline would better address the significant public safety and environmental risks grade 2 leaks entail. In addition, operators subject to the six-month default repair timeline for grade 2 leaks would be required to re-evaluate each grade 2 leak every 30 days until the leak has been repaired, which is intended to ensure that those leaks do not degrade into a grade 1 leak.

PHMSA proposes shorter repair deadlines for grade 2 leaks that are known on or before the effective date of a subsequent final rule in this proceeding. Further, PHMSA would require these leaks be repaired within one year from the publication date, consistent with the 12-month repair schedule in the GPTC Guide some operator practices may currently reference. Additionally, due to the greater public safety risks of a grade 2 leak from either a gas transmission or Type A gathering pipeline, each within HCAs or densely populated Class 3 or Class 4 locations, PHMSA proposes to require that these leaks be repaired within 30 days of detection, with an operator making continuous effort to monitor and repair the leak and eliminate the potential hazard if repairs cannot be completed within the prescribed timeline. As previously discussed in section II.C., leaks on gas transmission line pipe are less common than leaks on gas distribution pipeline pipe. However, a leak on a gas transmission or Type A gathering pipeline will likely result in greater release volumes and higher risk of ignition than distribution or Type B gathering lines due to the higher operating pressures and flow volumes typical of transmission and Type A gathering pipelines. The higher operating stress level on gas transmission and Type A gathering pipelines also entail a higher risk of rupture from degradation of leaks over time.

Lastly, PHMSA proposes to require each operator's leak grading and repair procedures to include a methodology for prioritizing grade 2 leak repairs, including criteria for determining leaks that must be repaired within 30 days or less. PHMSA's proposed criteria are based on calendar days rather than the working days under the GPTC Guide, which is consistent with existing guidance in Table 3a of the GPTC Guide. The operator's methodology must also include an analysis of the estimated volume of leakage since detection or the date of the last survey (whichever is earlier), migration of gas emissions, proximity of the leaking gas to buildings and underground structures, the extent of pavement, and soil types and conditions that affect the possibility for hazardous gas migration, such as frost conditions or soil moisture. This approach is consistent with the guidance in the GPTC Guide that certain grade 2 leaks justify repair on an accelerated schedule, and further mandates operators to consider safety and environmental protection when prioritizing repair efforts.

6. Grade 3 Leaks—§ 192.760(d)

PHMSA proposes that any leak that does not meet the criteria for a grade 1 or a grade 2 leak be classified as a grade 3 leak, which would be the lowest priority leak category. PHMSA has provided a non-exhaustive list of grade 3 criteria, including the following: a positive reading of less than 80% LEL in gas-associated substructures from which gas is unlikely to migrate, any positive reading under a street in an area without wall-to-wall pavement where gas is unlikely to migrate to the outside wall of nearby buildings, or a gas reading less than 20% LEL in a confined space. These examples are derived from the GPTC Guide, with additional clarifying language, ''from which gas is unlikely to migrate,'' consistent with PHMSA's understanding of the purpose of the pertinent GPTC Guide example.

The GPTC Guide and most State requirements do not define leak repair deadlines for grade 3 leaks. However, even a small leak can result in significant emissions and harm to the environment and public safety if it is allowed to release indefinitely without repair. Moreover, even small leaks have the potential to progress to more serious integrity incidents and failures, such that a grade 3 leak could develop into a more hazardous condition if ignored indefinitely. PHMSA therefore proposes a 24-month repair deadline for grade 3 leaks detected after the effective date of any final rule in this proceeding; this repair timeline would ensure timely repair of leaks while facilitating operator prioritization of repairs of higher-risk grade 1 and 2 leaks. This proposed repair schedule is 12 months more aggressive than the 36–month deadline adopted by the State of Texas, but consistent with other standards such as the delayed repair permitted for fugitive emissions monitoring in the EPA 40 CFR OOOOa standards for repairs where immediate repair is not feasible.[256] On the other hand, some States have more aggressive timelines, suggesting that the proposed timeline remains feasible for repair of buried pipeline facilities. For example, Missouri requires repair of ''class 2 leaks'' [257] within 45 days, unless the pipeline is scheduled for replacement within 1 year.[258] The 24-month repair deadline further ensures that all leaks discovered during a leakage survey are repaired prior to the next leakage survey (the longest proposed survey interval is once every 3 years for distribution pipelines outside of business districts, see proposed § 192.723), which would better prevent further growth in the backlog of unrepaired leaks than a 36-month repair deadline. Due to the likely large number of existing grade 3 leaks across the U.S., exemplified by the backlog of 10,000 unrepaired leaks on 11 New York distribution systems described in section II.D.3,[259] PHMSA proposes a repair deadline of 3 years after the publication date of the final rule for grade 3 leaks known to exist on or before the effective date of any final rule. This repair deadline is intended to give operators time to prioritize timely repair of higher-priority, previously-known-to-exist grade 2 leaks, while still ensuring timely repair of grade 3 leaks known to exist at the time a final rule publishes. Additionally, PHMSA proposes to require that each grade 3 leak must be re-evaluated at least once every six months until the repair of the leak is completed. The re-evaluation is designed to assess if the leak or the leak environment has changed in a way that may justify an upgrade to a grade 1 or grade 2 leak.

Lastly, as previously discussed in section II.E of this NPRM certain types of pipe materials cause a disproportionate number of leaks. In particular, pipe and fittings made of cast iron, unprotected steel, wrought iron, and historic plastics with known issues are more likely to leak than coated and protected steel and modern plastics. Replacing these pipelines and other pipelines known to leak can be an effective, long-term solution to systematic leak susceptibility for such pipelines. For example, in AGA's presentation at PHMSA's May 2021 public meeting on methane leak detection and repair, they noted that operators cast iron and bare steel distribution pipelines accounted for approximately 75 percent of reported leak repairs.[260] These replacement programs multiply benefits by eliminating both existing and future leaks. To accommodate pipe replacement programs, particularly on leak prone facilities, PHMSA proposes to allow that a grade 3 leak may be monitored rather than repaired if the leaking pipeline is scheduled for replacement or abandonment, and is in fact replaced or abandoned, within five years from the date of detection of the leak. This five-year timeline is intended to accommodate the time necessary for planning, permitting, engineering, design, and construction of pipeline replacement projects. This proposed timeline is consistent with PHMSA's Natural Gas Distribution Infrastructure Safety and Modernization Grants program, which permits applicants to elect a period of performance of up to 5 years for pipe replacement projects.[261] Due to the heightened potential hazards to public safety and the environmental, PHMSA does not propose a similar allowance for grade 1 and grade 2 leaks.

PHMSA seeks comments on the proposed repair timelines for grade 3 leaks (for potential inclusion within a final rule in this proceeding), including whether shorter repair timelines would be appropriate for grade 3 leaks existing as of publication of a final rule, or for grade 3 leaks eliminated by pipeline replacement. Comments on these questions are especially helpful when they provide specific suggestions supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

7. Post-Repair Inspection—§ 192.760(e)

PHMSA proposes to specify that a leak repair may only be classified as complete if the operator obtains during a post-repair inspection a gas concentration reading of 0% gas by volume at the leak location. The equipment used in leak investigations, including this post-repair inspection, must meet the proposed 5 ppm sensitivity standards in § 192.763(a)(1)(ii). This proposed inspection requirement ensures that the repair was effective and provides a definite, final repair date for operator records. For leaks that are eliminated by routine maintenance—such as cleaning, lubrication, or adjustment—a post-repair inspection would not be required for any leaks from aboveground facilities or for grade 3 leaks from other facilities.

PHMSA proposes that an inspection must occur between 14 and 30 days after the date of the repair. PHMSA intends the minimum interval before the first repair inspection to help ensure that the inspection accurately reflects the condition of the repair, since repairs may have a 0% reading at the moment of repair, but gas may leak over time from an incomplete repair or the repair may fail in a 14-day period. PHMSA is proposing a 30-day maximum to align with its proposed 30-day monitoring requirement for grade 2 leaks. If the operator is unable to achieve a 0% reading and determines that a grade 1 or 2 condition exists, PHMSA proposes that the operator must take immediate and continuous action to re-evaluate and remediate the repair so as to

[256] 40 CFR 60.5397a(h)(3).

[257] This term is unrelated to class 2 locations set forth in 49 CFR 192.5.

[258] 20 [Missouri] Code of State Regulations 4240–40.030(14)(C)(2).

[259] State of New York Department of Public Service, Case 21–G–0165, ''2020 Pipeline Safety Performance Measures Report'' at Appendix K (June 17, 2021).

[260] Sames, Christina. ''Pipeline Leak Detection, Leak Repair, and Methane Emissions.'' AGA. May 5, 2021. *https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1139.*

[261] *See* PHMSA, ''Frequently Asked Questions: FY 2022 Natural Gas Distribution Infrastructure Safety and Modernization Grant Notice of Funding Opportunity (NOFO)'' (July 29, 2022). FAQ 67 at page 16. *https://www.phmsa.dot.gov/grants/pipeline/ngdism-nofo-faqs.*

eliminate the leak. This proposed repair timeline could accelerate the repair of some grade 2 leaks. An accelerated timeline may be warranted because an incomplete or failed first attempt at leak repair could inhibit subsequent efforts to properly repair the leak. The proposed rule requires that if the post-repair inspection indicates a gas reading of greater than 0% gas and a grade 1 or grade 2 condition does not exist, the operator must remediate and re-inspect the repair every 30 days until it obtains a gas concentration reading of 0%. In this situation, remediation of a repair of a grade 3 leak would be completed before the initial repair deadline of 24 months from the date of initial detection. If a grade 3 condition exists during a post-repair inspection for a leak that was originally a grade 1 or grade 2 leak at the time of detection, the operator may consider downgrading the leak under proposed § 192.760(g), in which case the repair deadline is determined by the repair deadline proposed under § 192.760(h).

8. Upgrading and Downgrading—§ 192.760 (f) and (g)

PHMSA proposes to establish requirements for when and how a leak may be upgraded to a higher-priority grade or downgraded to a lower-priority grade. Section 192.760(f) would require that if an operator receives information that a higher-priority grade condition exists on a previously graded leak, the operator must upgrade the leak to that new grade. For a leak that is upgraded, the repair deadline is the earlier of the remaining repair deadline for the original grade, or the repair deadline under the new leak grade measured from the date the operator receives the information that a higher-priority grade condition exists. This proposed approach would provide certainty regarding the repair deadline for an upgraded leak, while avoiding the perverse consequence that upgrading a leak would allow a more permissive repair schedule.

PHMSA also proposes to allow downgrading a leak grade only if a repair has been attempted. This approach would allow downgrading a leak only if the operator performed a temporary repair or attempted a permanent leak repair but did not obtain a 0% gas reading during the post-repair inspection under proposed § 192.760(e). This would prevent practices such as downgrading a leak after venting until gas concentration falls below a grade 1 or grade 2 criteria, without an effort to repair the leak itself. If a leak is downgraded, PHMSA proposes the time period for repair would be the remaining time allowed for repair for the downgraded leak measured from the time the leak was first detected—an approach PHMSA expects would incentivize timely completion of downgraded repairs and prevent extension of repair timelines through pretextual attempts at permanent repair.

9. Extension of leak repair—§ 192.760(h)

PHMSA proposes to allow an extension of the repair deadline requirements for individual leaks on a case-by-case basis. Any extension requires notification to, and review by, PHMSA pursuant to the procedures in § 192.18. Leak repair extensions under § 192.760(h) may be requested only if (1) the leak repair pursuant to an alternative schedule would not result in increased public safety risk, and (2) the operator can demonstrate that the prescribed repair schedule is impracticable, an alternative repair schedule is necessary for safety, or remediation within the specified time frame would result in the release of more gas to the environment than would otherwise occur if the leak were allowed to continue. For example, an alternative repair schedule may be warranted if remediation within the timeframe proposed in this NPRM would result in the release of more gas to the environment from blowdown—delayed repair could minimize emissions by coordinating blowdowns with other maintenance activity, while offering the safety benefit of fewer emissions that could ignite. PHMSA proposes to limit the extensions to grade 3 leaks, which inherently pose lower risks to public safety and the environment than grades 1 and 2 leaks. The notification to PHMSA would need to include a description of the leak, the leaking pipeline, the leak environment, any proposed monitoring and extended repair schedule, the justification for an extended repair schedule, and proposed emissions mitigation methods.

10. Recordkeeping—§ 192.760(i)

PHMSA proposes certain recordkeeping requirements for leak detection, investigation, grading and repair activity. Section 192.760(i) would describe recordkeeping requirements associated with leak grading and repair; PHMSA proposes that records documenting the complete history of investigation and grading of each leak prior to completion of the repair would need to be retained until five years after the date of the final post-repair inspection performed under proposed paragraph § 192.760(e). Pertinent records would include documentation of grading monitoring, inspections, upgrades, and downgrades. PHMSA also proposes that records associated with the detection, remediation, and repair of each leak must be maintained for the life of the pipeline. This permanent recordkeeping would apply to both piping and non-piping portions of the pipeline. Should leak detection occur during a patrol, survey, inspection, or test, the pertinent portion of documentation for that patrol, survey, inspection, or test would need to be retained pursuant to proposed § 192.760(i). These proposed documentation requirements would support periodic evaluation and improvement of their ALDPs pursuant to proposed § 192.763(a)(4) as well as regulatory oversight activity by PHMSA and its State partners.

D. Qualification of Leakage Survey, Investigation, and Repair Personnel—§ 192.769

Proposed § 192.769 would require that operator personnel engaged in leakage surveys, and the investigation and repair of leaks discovered on each of gas transmission, distribution, offshore gathering, and Type A regulated onshore gathering [262] pipelines are subject to the personnel qualification requirements at part 192 in performing those activities. PHMSA proposes to clarify that leakage surveys, investigation, and repair activities are ''covered tasks'' under part 192, subpart N and therefore covered by operator qualification requirements in that subpart. These operations and maintenance functions are critical to ensuring the proper operation and integrity of gas pipelines, and therefore meet the criteria for the four-part test for defining covered tasks in § 192.801(b) (tasks that are performed on a pipeline facility; are operations or maintenance tasks; are required by part 192; and affect the operation or integrity of the pipeline). Therefore, the proposed revision would help ensure baseline regulatory requirements for personnel qualification are met when performing those activities.

PHMSA understands that the proposed personnel qualification requirements discussed above would be reasonable, technically feasible, cost-effective, and practicable for affected gas pipeline operators. PHMSA understands

[262] PHMSA regulations at § 192.9(c) allow operators of Type A gas gathering pipeline to employ less comprehensive programs in satisfying subpart N personnel qualification requirements than employed by certain other part 192-regulated gas pipelines. PHMSA is not proposing a different approach for personnel qualifications with respect to personnel conducting leakage surveys and investigation and repair of leaks on Type A gas gathering pipelines.

that some affected operators may already have adopted (either voluntarily or in response to State or Federal requirements) compliant training and personnel practices, or would be able to adapt existing practices with minimal effort—particularly as ensuring personnel employed in conducting leakage surveys, inspection, and repair activities is a practice that reasonably prudent operators would adopt in ordinary course to protect public safety and the environment from release of pressurized (natural, flammable, corrosive, and toxic) gases transported in their pipelines and minimize loss of commercially valuable commodity. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the NPRM's proposed compliance timelines—which are based on an effective date of six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to develop and provide the requisite training for their personnel (or otherwise obtain access to qualified personnel) and manage any related compliance costs. PHMSA seeks comments on whether, within a final rule in this proceeding, it would be appropriate to apply the proposed operator qualification requirements in § 192.769 to Type B and Type C regulated onshore gas gathering lines or UNGSFs, which are not currently required to comply with subpart N. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of that approach, including whether that approach would be technically feasible, cost-effective, and practicable. For gas gathering pipelines, this could entail subjecting Type B and applicable Type C gathering pipelines to simplified subpart N requirements similar to Type A lines in Class 1 locations and could either apply generally to all covered tasks, or only for leak detection, grading, and repair activities.

E. Reporting and National Pipeline Mapping System—§§ 191.3, 191.9, 191.11, 191.17, 191.19, 191.23, and 191.29

PHMSA proposes new and revised reporting requirements to collect more data on pipeline leaks and other emissions. The most significant proposed revisions would create a large-volume gas release report to supplement existing incident reporting requirements. As is the case for incident reports, this requirement would apply to any gas pipeline facility covered under part 191, including jurisdictional storage and part 193 LNG facilities. Additionally, PHMSA proposes to revise the gas transmission, offshore gathering, and Types A, B, and C gathering, and distribution annual report forms to include each of (1) estimated aggregate emissions from all leaks existing on the system within the calendar year by grade (including emissions within the calendar year from leaks discovered in prior years), (2) other methane emissions by source category, and (3) the number of leaks detected and repaired by grade. PHMSA solicits comments on the potential utility of requiring operators to report more granular leak data, such as individual leak location, individual leak emissions, or individual leak repair timing, in addition to the information described above. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

Existing § 191.3 defines an incident as a release from a gas pipeline facility that results in death or serious injury, property damage of $122,000 [263] or more in calendar year 2021, or an unintentional release of 3 MMCF or more of gas. While incident reports provide valuable information on major emissions events with critical safety consequences, existing incident reporting criteria and the exclusion of intentional releases from reporting requirements means the current reporting scheme does not capture data on many significant emissions events.

PHMSA therefore proposes at § 191.19 to require a new report for intentional and unintentional releases with a volume of 1 MMCF or greater, excluding certain events that had been reported as incidents under §§ 191.9 or 191.15. For illustration, routine leaks with an emissions rate of 10 CFH consistent with the proposed grade 2 emissions criteria at § 192.760, would not be reported individually under this section if they are repaired within the proposed repair schedule (note that a count of all leaks would be reported on annual reports), but larger leaks exceeding 100 kg/hr. ''super-emitter'' criteria contemplated by the EPA in their December 6, 2022 supplemental notice of proposed rulemaking [264] would be reported if they were not promptly repaired such that their aggregate emissions were below the 1 MMCF threshold. Blowdowns of high-pressure lines without mitigation measures such as those proposed in § 192.770 may also meet the 1 MMCF threshold depending on the pressure and volume of the blowdown segment. Operators would be required to submit a report within 30 days from the date that a release known at detection to be 1 MMCF or more was detected, or 30 days from the date that a previously detected release became reportable. If the time the leak started is unknown, operators should base the calculation based on estimated release volume from the date of the most recent leakage survey. PHMSA proposes an exception from § 191.23 safety-related condition reporting requirements for events that are reported as large-volume gas releases. This proposed exception for large-volume incident reports would be consistent with the existing exception at § 191.23(b) for events reported as incidents.

These new, large-volume gas release reports would provide valuable information on the primary sources and causes of vented emissions and the causes of large-volume leaks that do not qualify as incidents, addressing information gaps in the current incident reporting requirements. First, information on vented emissions is not currently collected on incident or annual report forms. The new report would provide PHMSA and other interested stakeholders information on the causes, consequences, and frequency of intentional, large-volume, vented emissions to provide both regulators and operators the information necessary to prevent reoccurrence. That information would be also particularly useful for PHMSA and State regulatory authorities in ensuring operator compliance with the self-executing mandate within section 114 of the PIPES Act of 2020 for operators to update their inspection and maintenance procedures to provide for minimization of releases of gas from their pipeline facilities. Second, PHMSA's proposed 1 MMCF threshold for the new large-volume gas release report is significantly lower than the 3 MMCF threshold required under the current incident reporting regulations, allowing PHMSA to collect detailed

[263] Adjusted for inflation on an annual basis.

[264] EPA, ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,'' 87 FR 74702, 74707 (Dec. 6, 2022).

cause and consequence information on large-volume, intentional and unintentional releases that may not be collected on incident reports. PHMSA solicits comment on whether alternative reporting thresholds for either large volume gas releases or incidents, including thresholds below 1 MMCF, would provide higher-quality information than PHMSA's proposed 1 MMCF threshold. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

PHMSA proposes to include the above information on a new report rather than by revising the incident definition at § 191.3 to collect focused information on fugitive and vented emissions that do not satisfy incident reporting criteria. Operators of all gas pipeline facilities would remain required to submit incident reports if unintentional releases reported under this new requirement subsequently satisfy incident reporting criteria. Operators who have already submitted an incident report would not need to file a large-volume gas release report under § 191.19 for the same event so long as the release volume in the incident report is within 10 percent of the total release volume on cessation of the release. PHMSA intends for the large-volume gas release reporting requirement to extend to Type R gas gathering pipelines to inform PHMSA's consideration of whether fugitive and vented emissions from those pipeline facilities warrant extension of part 192 requirements.

PHMSA proposes to clarify what is considered property damage for the purpose of determining whether a release is reportable as an incident pursuant to §§ 191.9 or 191.15. Specifically, PHMSA proposes revision of the definition of ''incident'' at § 191.3 to exclude, when calculating estimated property damage, costs associated with each of obtaining permits and removal or replacement of infrastructure undamaged by the event (*e.g.,* pavement needed for access and repair activity) in connection with an event. This change would respond to NAPSR Resolution 2021–01, ''A Resolution Seeking a Modification of PHMSA's Instructions for Incident Reporting for Gas Distribution, Gas Transmission, and Gas Gathering Systems,'' [265] which concerns how to classify overall secondary damage beyond the primary damage from an incident. Operators would still report these costs as incident consequences on the applicable incident report forms; however, they should not be included in the calculation of property damage for determining whether a release is reportable as an incident.

PHMSA also proposes changes to the gas distribution, transmission, offshore gathering, and regulated onshore gas gathering annual reports required by §§ 191.11 and 191.17, consistent with other proposed changes regarding leak grading and repair on those facilities and to collect information on estimated total emissions from each of (1) leaks existing on the operator's system during the calendar year by grade and (2), other emissions by source category. The source categories generally mirror the categories in the GHGI, as summarized in section II.C.2. While existing annual report forms include limited data on leaks repaired in the preceding year, they lack other data—including the number and grade of leaks detected in the preceding year, the grade of leaks repaired in the preceding year, and estimated release volumes from those leaks—important for PHMSA and State regulators to understand the frequency of leaks, the significance for public safety and the environment from those leaks, and adequacy of operator leak detection and repair programs. PHMSA therefore proposes to revise the annual report forms for operators of gas distribution, offshore gathering, regulated onshore gathering, and transmission pipeline facilities to collect data on each of the following: the number of leaks detected and repaired by grade (see proposed § 192.760); the estimated aggregate emissions from all existing leaks (whether detected in the reporting year or not) by grade, and estimated emissions from other sources by source categories. PHMSA further proposes that, because this NPRM does not provide for leak grading requirements for LNG facilities, operators of those facilities would need to report data on each of the number of methane leaks detected and repaired during the annual reporting period pursuant to proposed § 193.2624, the number of unrepaired leaks at the end of the annual reporting period, and estimated fugitive methane emissions (each by EPA GHGRP source category) from all methane leaks identified pursuant to proposed § 193.2624. PHMSA is not proposing similar enhanced annual reporting requirements for Type R gathering pipelines because those facilities would not be subject to the leak grading and repair requirements at § 192.760. However, PHMSA sees value in reviewing the results of recently-adopted incident and annual reporting requirements for those pipelines under the Gas Gathering Final Rule, as well as the large-volume gas release reporting requirements proposed herein, to inform a path forward regarding expanding annual reporting requirements for Type R pipelines.

For emissions reporting, PHMSA proposes operators provide aggregate emissions estimate for leaks by grade. PHMSA also proposes to collect estimated annual emissions by source category, which includes both leaks, incidents, and vented emissions. The source categories generally mirror the categories in the GHGI and as summarized in section II.C.2. This approach would ensure that both EPA and PHMSA have high-quality leak emissions data to support their distinguishable, but mutually-reinforcing, regulatory responsibilities. For PHMSA aggregate emissions data provided on a per-leak grade basis would be particularly useful in informing future decision-making calibrating part 192 safety requirements based on an evolving understanding of the safety and environmental hazards posed by different grades of leaks. Similarly, information on other emissions would better inform Federal, State, and operator efforts to minimize avoidable vented emissions, which is required under section 114 of the PIPES Act of 2020. PHMSA would require that, in developing aggregate emissions estimates, operators would employ direct measurement and/or top-down methodologies along the lines of those discussed in section III.C.2 above.[266]

PHMSA also proposes to require operators to submit geospatial data about offshore gas gathering and Type A, Type B, and Type C gathering pipelines to the NPMS. The NPMS is a geographic information system (GIS) that contains the locations and related attribute data for a variety of pipeline facilities. The NPMS was established via a self-executing requirement codified in 49 U.S.C. 60132; while that statutory mandate excluded distribution and gathering lines, PHMSA has authority elsewhere in the Federal Pipeline Safety Laws at 49 U.S.C. 60117(c) to collect safety data for gathering pipelines to inform whether and how to provide

[265] *http://www.napsr.org/resolutions.html.*

[266] PHMSA would also consider estimated emissions methodologies employed by EPA-qualified third-party notifiers in reporting leaks under EPA's super-emitter response program proposals within its supplemental notice of proposed rulemaking issued under RIN 2060–AV16. *See* EPA SNPRM.

regulatory oversight of those facilities. Pipeline safety stakeholders—including journalists, operators, emergency responders, excavators, elected officials, public interest advocates, and PHMSA and State regulators—use the NPMS to obtain important pipeline-safety related information, including the locations of pipelines and related infrastructure, the names and contact information of pipeline operators, and other attributes of pipelines such as commodities transported and diameter.[267] In particular, access to gathering pipeline geospatial data on NPMS would reinforce damage prevention programs required under § 192.614. Emergency responders often use the NPMS to identify pipelines in the vicinity of reported leaks and contact relevant operators. Emergency responders and pipeline operators also use the NPMS while conducting drills and exercises to support operators' emergency response plans. The requirement to submit data to the NPMS would also reinforce operators' efforts in developing and maintaining adequate maps and records of their systems.

In addition to the benefits detailed above, PHMSA expects that its proposed amendments to NPMS requirements may also improve operators' leak detection programs. First, it would ensure that operators know the location of their pipelines; accurate location information can improve the accuracy of leakage surveys and patrols for buried pipelines, especially for leakage surveys performed with handheld equipment. Second, if a pipeline is in the NPMS, it is easier for third parties such as other operators, researchers, or the public to report leaks, ruptures, and other unsafe conditions to the operator. Public interest groups and aerial survey technology providers have noted that they have had difficulty identifying the operator of a facility where a leak indication was detected. PHMSA solicits comment on whether, within a final rule in this proceeding, it would be appropriate to require NPMS participation for Type R gathering pipelines not regulated under part 192. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of that particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

While operators may engage third parties as part of their efforts to comply with the requirements proposed herein (for example, by contracting with vendors of technologies such as those discussed in section II.D.4 above), PHMSA has not proposed in this NPRM any formal role for third parties in the detection or reporting of leaks or intentional emissions. PHMSA invites comment on whether PHMSA should revise § 192.605 to address operators' procedures for responding to third-party reports of gas releases or otherwise incorporate elements from or leverage EPA's super-emitter response program proposed in the EPA SNPRM for third party leak reporting[268] as a backstop to support the reporting requirements proposed herein (for potential inclusion within a final rule in this proceeding), including whether data from such third party leak reporting should be included in operator reports to PHMSA (including aggregate emissions estimates by grade). PHMSA further invites comment on whether to facilitate third party reporting of operator non-compliance with the proposed requirements in this rulemaking (or any other provision of PHMSA regulations) to the attention of PHMSA enforcement personnel or State partners. Comments on these questions are especially helpful to PHMSA when they identify specific proposals supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

PHMSA understands that the proposed enhanced reporting and NPMS requirements discussed above would be reasonable, technically feasible, cost-effective, and practicable for affected gas pipeline operators. The contents of PHMSA's proposed new large-volume gas release report will resemble longstanding incident reporting requirements applicable to unintentional releases from part 192-regulated gas pipelines. Meanwhile, PHMSA's proposed enhanced annual reporting requirements for leak and repair activity would largely consist of reporting of information obtained from operator efforts in complying with the enhanced leak detection and repair requirements proposed elsewhere in this NPRM. Meanwhile, PHMSA's proposal to extend NPMS requirements to all part 192-regulated gas gathering lines would merely require those operators to submit information (including the precise location of their pipelines, the commodity transported, etc.) that reasonably prudent operators would maintain in ordinary course to protect public safety and the environment from the pressurized (natural flammable, corrosive, or toxic) gases transported in their pipelines. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments to part 191 reporting requirements will be a cost-effective approach to obtaining enhanced data on intentional and unintentional releases of methane and other part 192-regulated gases necessary to inform PHMSA enforcement, policy development, and incident avoidance and response efforts. Lastly, the NPRM's proposed compliance timelines with those proposed reporting requirements—which are based on an effective date of six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to design and implement requisite protocols and manage any related compliance costs.

F. Mitigating Vented and Other Emissions From Gas Pipeline Facilities—§§ 192.9, 192.12, 192.605, 192.770, 193.2503, 193.2523 and 193.2605

In light of the significant methane emissions associated with blowdowns and other vented gas emissions from PHMSA-jurisdictional gas pipeline facilities, and to facilitate operator implementation of the self-executing mandate in section 114 of the PIPES Act of 2020, PHMSA proposes to incorporate that statutory language within the Pipeline Safety Regulations.[269] Specifically, PHMSA proposes to incorporate an explicit requirement to eliminate leaks of all flammable, toxic, or corrosive gases, as well as minimize releases of natural gas, within provisions prescribing the content of operating, emergency, and maintenance manuals for gas transmission, distribution, Type A gathering and offshore gathering pipelines (§ 192.605 via current § 192.9), Types B and C gathering pipelines (§ 192.605 via a revised § 192.9(d) and (e)), UNGSFs (§ 191.12(c)), and part 193 LNG facilities (§§ 193.2503 and 193.2605). The proposed broad-based incorporation of the PIPES Act of 2020 section 114 mandate would promote operator compliance efforts by aligning

[267] PHMSA acknowledges that stakeholders do not have uniform access to information within NPMS.

[268] *See* EPA SNPRM, 87 FR at 74746.

[269] PHMSA has, pursuant to section 114 of the PIPES Act of 2020, initiated a study on the best available technology or practices to reduce methane emissions associated with design, construction, operations, and maintenance of pipeline facilities, and will initiate a rulemaking based on the results of that study.

PHMSA's regulatory requirements with the statutory mandate and helping to ensure that leak elimination and natural gas release mitigation inform the spectrum of operator activities. The proposed regulatory text would reinforce other operator obligations (including, but not limited to, repair criteria and IM requirements) throughout PHMSA regulations that improve safety, environmental protection, and U.S. competitiveness.

PHMSA proposes that operators of gas transmission, offshore gathering, Type A gathering, and part 193 LNG facilities would have to adopt specific requirements for minimizing the release of gas during non-emergency blowdowns, LNG tank boil-offs, and other vented emissions events. According to GHGI data described in section II.C of this NPRM, approximately one-fourth of annual methane emissions from U.S. natural gas transmission pipelines are from vented emissions, including blowdowns. For LNG facilities, blowdowns represented around 48% of methane emissions, and as much as 80% of methane emissions from storage appurtenant to LNG facilities. PHMSA also notes that boil-offs of LNG storage tanks at part 193 LNG facilities to accommodate maintenance activity are similar in function to blowdowns on part 192 pipeline facilities—and similarly can be significant contributors of methane emissions if released to atmosphere.[270] Mitigation of non-emergency vented emissions as an important opportunity for reducing methane emissions. The EPA Natural Gas STAR program listed blowdown volume mitigation among several cost-effective and recommended technologies for reducing methane emissions from operations, maintenance, and construction.[271]Additionally, the ''Best Management Practice'' commitment option for EPA's voluntary Methane Challenge program identifies various methods of reducing or eliminating blowdown emissions volumes similar to those proposed in this NPRM.[272] The PST has identified similar mitigation options in public comments to rulemaking actions dating from 2016, and INGAA included minimizing blowdown volume in a list of commitments that member companies are making to address methane emissions.[273]

PHMSA therefore proposes to amend its regulations pertaining to each of gas transmission, regulated offshore gathering, and Type A gathering pipelines (§ 192.770) and part 193 LNG facilities (§ 193.2523) to identify a menu of proven options—many of them featuring prominently in the voluntary initiatives described in the preceding paragraph that operators must choose from to mitigate methane releases during blowdowns, tank boil-offs, and other vented emissions.

Proposed §§ 192.770(a) and 193.2523(a) include an option to install and use valves or control fittings to reduce the volume of gas that must be removed from pipeline facility segments. Instead of blowing down a pipeline facility between mainline block valves or compressor stations, the operator would isolate a shorter segment of pipe, resulting in lower release volumes. In addition to the emissions abatement benefits from isolating shorter segments for maintenance tasks, this approach can have operational benefits from reducing or eliminating downtime by bypassing the shut-in segment. A second proposed method is routing vented gas to a flare stack to be ignited or to other equipment to be collected for later use. Burning gas rather than releasing it into the atmosphere significantly reduces the climate change impacts of vented emissions by converting methane gas to carbon dioxide and water via combustion. Under favorable conditions a well-designed and maintained flare stack can combust gas with almost 100% efficiency, however leaks and unlit or incomplete flaring (due to poor maintenance, design, or operation practices) can reduce the methane reduction efficiency on a field-level basis to approximately 90%.[274] Leaks and releases from flaring equipment would be subject to the proposed amendments in this NPRM as components of a ''pipeline'' as defined in parts 191 and 192. Routing or recovering gas for use as a fuel source is similar in principle to flaring. The third, fourth, and fifth approaches identified in proposed §§ 192.770(a) and 193.2523 involve reducing pressure (or, in the case of LNG tank boil-off, LNG volumes) of a pipeline segment prior to venting, thereby reducing total emissions volume. In the third approach, an operator would isolate the pipeline segment upstream of the vented segment and use the downstream compressor station to reduce the pressure of the affected segment. The fourth approach is similar except instead of the compressor station, an operator would use a mobile compressor unit to reduce the pressure of the segment by compressing gas, or diverting LNG, into adjacent facilities or a storage vessel. The fifth approach—transferring gas or LNG to a lower-pressure pipeline segment—is like the fourth, except it may be performed without compression in certain circumstances. PHMSA seeks comment on whether it is appropriate to specify a minimum pressure or pressure reduction in the vented segment for pressure reduction methods and any other mitigation measures operators should consider. Lastly, PHMSA proposes that operators be able to employ alternative approaches not listed in §§ 192.770(a) and 193.2523(a) for release volume mitigation, provided that the operator can demonstrate that a proposed approach reduces the volume of released gas by at least 50% compared with taking no mitigative action. This is consistent with the approach used in the EPA's Methane Challenge[275] program and would provide operators with flexibility to employ techniques and technologies appropriate for the unique operating and environmental conditions of their facilities and would accommodate future advancements in release mitigation technologies and practices. PHMSA invites comment on whether, for any (or all) of the release volume mitigation approaches proposed in §§ 192.770(a)(1) through (5) and 193.2523(a)(1) through (3), operators should be required to demonstrate that a particular approach reduces the

[270] Vented and other releases of cryogenic LNG to the atmosphere also present unique safety hazards and can cause flammable vapor clouds, jet or pool fires in the presence of an ignition source, or a sudden and explosive phase change if LNG encounters a warm surface such as water. When spilled directly onto water, LNG can rapidly convert from liquid to gaseous phase, releasing enough energy to cause a physical explosion without any combustion or chemical reaction. *See* World Bank Group, Environmental, Health, and Safety Guidelines: Liquefied Natural Gas Facilities (2017). In addition, vented releases of unprocessed gas results in the release of VOCs and HAPs that entail distinguishable environmental and public safety harms.

[271] *See* PRO Fact Sheets Nos. 401, *https://www.epa.gov/sites/default/files/2016-06/documents/injectblowdowngas.pdf.*

[272] EPA, ''Natural Gas STAR Methane Challenge Program: BPM Commitment Option Technical Document'' (May 2022), *https://www.epa.gov/system/files/documents/2022-05/MC_BMP_TechnicalDocument_2022-05.pdf* (last accessed Dec. 20, 2022).

[273] *https://www.ingaa.org/File.aspx?id=38582; https://www.regulations.gov/comment/PHMSA-2011-0023-0272.*

[274] Duren, Riley and Deborah Gordon. ''Tackling unlit and inefficient gas flaring,'' *Science.* Vol. 337 Issue 6614. (2022): 1486–1487. *https://www.science.org/doi/full/10.1126/science.ade2315.*

[275] *See* EPA, ''Methane Challenge Program BMP Commitment Option Technical Document'' at pg. 21 (May 2022), *https://www.epa.gov/system/files/documents/2022-05/MC_BMP_TechnicalDocument_2022-05.pdf* (last accessed March 16, 2023).

volume of released gas by at least 50% compared with taking no action (consistent with the EPA's Methane Challenge program) (for potential inclusion within a final rule in this proceeding). PHMSA further invites comment on whether a different minimum percentage reduction (higher or lower than 50%) would instead be more appropriate for any (or all) of the release volume mitigation approaches proposed in §§ 192.770(a) and 193.2523(a) (for potential inclusion within a final rule in this proceeding). Comments on each of these questions are especially helpful when they are supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

PHMSA further proposes in §§ 192.770(c) and 193.2523(c) that those operators develop documentation describing the suite of actions undertaken—including, but not limited to, their choice from among the blowdown mitigation method(s) identified in either §§ 192.770(a) or 193.2523(a)—to minimize vented emissions from their systems. PHMSA does not propose to require mitigation for emergency blowdowns pursuant to an emergency plan under §§ 192.615(a)(3) or 193.2509 so as to ensure that emissions mitigation will not come at the expense of public safety and other environmental resources; however, PHMSA proposes at §§ 192.770(b) and 193.2523(b) to require that operators document such events, including the justification for not taking mitigative action.[276]

PHMSA understands that its proposed requirements for minimizing vented and other releases from certain gas pipeline facilities discussed above would be reasonable, technically feasible, cost-effective, and practicable for affected gas pipeline operators. PHMSA understands that some affected operators may already have adopted protocols for minimizing vented emissions and eliminating leaks from their facilities either voluntarily (*e.g.,* to minimize loss of a commercially valuable—and hazardous—commodity) or in response to State or Federal requirements (including, but not limited to, the self-executing mandate in section 114 of the PIPES Act of 2020). The NPRM reinforces those efforts by codifying that self-executing statutory mandate in the pipeline safety regulations. Similarly, PHMSA's proposals accommodate a variety of compliance strategies; the text of pertinent regulatory provisions contains a non-exclusive menu of compliant approaches from which operators can choose as appropriate for their needs and their facilities' operational characteristics and environment. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the NPRM's proposed compliance timelines—which are based on an effective date of six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to develop and implement compliance protocols and manage any related compliance costs.

Although the NPRM does not include a similar prescribed menu of required blowdown emissions mitigation approaches for gas distribution or Types B and C gathering pipelines due to the comparatively smaller blowdown volumes of some of those systems, PHMSA seeks comment on whether, within a final rule in this proceeding, it would be appropriate to require use of some of the methods for mitigating transmission pipeline and LNG facility blowdown emissions proposed herein for use on gas distribution or Types B and C gathering pipelines. PHMSA also seeks comment on whether it is appropriate to restrict the use of flaring to instances where other mitigation measures are impracticable. Comments on these questions are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

The proposals described in this section are intended to codify section 114(a) and (b) of the PIPES Act of 2020 and address a subset of operations and maintenance-related emissions sources. PHMSA has a separate Congressional mandate under section 114(d) of the PIPES Act of 2020 to promulgate pipeline design, operations, and maintenance requirements to ''prevent or minimize, without compromising pipeline safety, the release of natural gas'' in connection with intentional operator releases. PHMSA will address this mandate in a future rulemaking action following the completion of a report to Congress discussing the best available technologies, practices, and designs to prevent or minimize such releases (per section 114(d)(1) of the PIPES Act of 2020).[277] Specifically, the report must evaluate pipeline facility designs that mitigate the need to intentionally vent natural gas (without compromising pipeline safety) as well as the best available technologies or practices to prevent or minimize (without compromising pipeline safety) the release of natural gas when making planned repairs, replacements, or maintenance to a pipeline facility and when the operator intentionally vents or releases natural gas, including blowdowns. As of the date of issuance of this final rule, PHMSA is in the process of developing the best available technologies and practices report referenced in section 114(d)(1).

G. Design, Configuration, and Maintenance of Pressure Relief Devices—§§ 192.9, 192.199 and 192.773

PHMSA proposes to minimize emissions caused by malfunctioning pressure relief devices and other unnecessary releases from poorly designed or configured pressure relief devices. A pressure relief device vents gas to the atmosphere (or to a flare) when the pressure in the system satisfies either design or configuration actuation criteria,[278] to protect the integrity of the facility from an overpressure condition. A pressure relief device may malfunction by not releasing gas as required by those criteria, risking an overpressure condition that can induce a loss of system integrity and release of gas to atmosphere. Alternatively, a pressure relief may malfunction by operating before those criteria have been satisfied, which results in unnecessary releases of gas to the atmosphere. Similarly, a pressure relief device with design or configuration actuation criteria more conservative than necessary to provide

[276] Note that a blowdown that is not mitigated may also be reportable under the proposed large-volume gas release report.

[277] Section 114(d)(2) of the PIPES Act of 2020 requires the Secretary to update the Pipeline Safety Regulations that the Secretary has determined are necessary to protect the environment without compromising safety within 180 days after submitting the section 114(d)(1) report.

[278] PHMSA here draws a distinction between design actuation criteria set by a device manufacturer (which generally cannot be changed by an operator) and configuration actuation criteria (which in some cases could be changed by an operator post-manufacture and installation). PHMSA further notes that by ''actuation criteria'' it means the suite of setpoints (*e.g.,* pressure) and other conditions (*e.g.,* programmable logic) that must be satisfied for a pressure relief device to actuate and cease actuation. For example, actuation criteria may consist of a pressure setpoint at which a pressure relief valve may open, as well as a setpoint for that same valve to close.

adequate margin to an overpressure condition can also result in unnecessary gas releases. Additionally, a pressure relief device whose design or materials are ill-suited for use in a pipeline facility's particular operating and environmental conditions may fail or leak.

PHMSA often receives reports of major releases from pressure relief device failures: since 2010, operators have submitted 112 incident reports for releases from pressure relief devices on gas transmission and regulated gas gathering pipelines from 2010 through the end of 2022, reporting an average release volume of 12.5 MMCF from each event. The largest relief device failure reported to PHMSA occurred on November 22, 2014, when an 8-inch relief valve on a 34-inch gas transmission pipeline operated by Pacific Gas and Electric (PG&E) malfunctioned, which released 119 MMCF of natural gas into the atmosphere until operating personnel were able to bypass the valve. Following the incident, PG&E contractors performed a root cause analysis and made unspecified changes to the pressure limiting station pending a future redesign.[279]

Out of these incident reports 84 were caused by a malfunction of the relief device or other pressure control equipment.

GAS TRANSMISSION AND REGULATED GAS GATHERING PRESSURE RELIEF DEVICE INCIDENTS

Primary cause and sub-cause	Incidents 2010–2022
Equipment failure: malfunction of control/relief equipment	84
Equipment failure: other equipment failure	5
Equipment failure: threaded connection/coupling failure	2
Equipment failure: defective of loose tubing/fitting	1
Incorrect operation: other incorrect operation	8
Incorrect operation: pipeline/equipment over pressurized	3
Incorrect operation: incorrect valve position	2
Incorrect operation: incorrect equipment	1
Natural force damage: temperature	4
Miscellaneous	2
Total	112

The most common causes of these failures according to narratives in part G6 or H of operator's gas transmission incident reports are mechanical failures of the relief device, including failures to reseat or reseal after activation, and failures caused when liquid contaminants cause a relief device to freeze open or closed in cold weather conditions. Other reported incidents have resulted from the use of pressure relief devices whose design and material were inappropriate for the pipelines on which they were installed and expected operating conditions. For example, incidents were attributed to improper calibration, design issue with the location of the sensing line, pressure programming or setting issues, improper setpoint, construction, or programming issues, an oversized or undersized pressure relief device and inlet piping, high pipeline flow conditions, and setpoint drift.

Other data sources suggest these incident report figures may undercount relief device emissions that could be prevented through better design, configuration, and maintenance. For example, PHMSA receives inquiries from media sources based on satellite documentation of significant methane releases. Additionally, PHMSA is notified of National Response Center reports on releases involving pressure relief devices in accordance with § 191.5 approximately once a week, with 39 NRC reports referencing relief valves in the description in calendar year 2021.[280] Operators report such releases to the National Response Center more frequently than they file incident reports pursuant to §§ 191.9 or 191.15, which suggests that operators may—after reporting them to the National Response Center immediately after discovery of a release—subsequently designate some emissions from relief devices as ''intentional'' emissions that are not required to be reported to PHMSA as incidents.[281]

Overpressurization is a critical safety issue and can result in a pipeline incident or rupture with grave public safety and environmental consequences. However, inadequate design and configuration of pressure relief devices may result in potentially very large releases beyond that necessary to provide overpressure protection. Additionally, relief device malfunctions due to inadequate maintenance or other issues can result in a failure to provide reliable overpressure protection if it fails to operate or significant emissions if the device leaks or operates unintentionally. PHMSA has observed through inspections and other regulatory oversight activities, that operator procedures, including the choice of design and configuration actuation criteria, may not be optimized to reduce emissions associated with pressure relief device malfunctions or operations beyond what is necessary to provide overpressure protection. For example, some operators take an overly conservative approach to avoiding overpressure conditions and employ design and configuration actuation criteria such that those pressure relief valves will release gas to the atmosphere either more frequently or in greater quantities than necessary to protect against an overpressure condition.

PHMSA proposes to revise § 192.199 to require operators of all new and replaced, relocated, or otherwise changed gas transmission, distribution, and part 192-regulated gathering pipelines be designed and configured, as demonstrated by documented engineering analysis, to minimize unnecessary releases of gas. Section 192.199 would prescribe a series of elements that operators must demonstrate would minimize emissions using engineering analysis. These elements include the choice of design material and function, configuration actuation conditions, pressure relief device piping characteristics, presence of isolation valves to facilitate testing and maintenance, and compatibility of material and design with use. In addition, PHMSA proposes a new § 192.773 that, coupled with proposed revisions to § 192.9, would require operators of all gas transmission, distribution, and part 192-regulated gathering pipelines to develop procedures to assess the proper function of pressure relief devices on their facilities and remediate or replace any

[279] PHMSA, ''Pipeline Incident Flagged Files'', *https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files* (last accessed Dec. 20, 2022) (memorialized within Report ID No. 20140148).

[280] United States Coast Guard, National Response Center, *https://nrc.uscg.mil/* (last accessed Dec. 20, 2022).

[281] The discrepancy between events reported to the National Response Center pursuant to § 191.5 and those ultimately reported as incidents pursuant to §§ 191.9 or 191.15 reflects a difference in timing between these two reporting requirements: the § 191.5 reporting requirement obliges operators to notify the National Response Center at ''the earliest practicable'' moment—which in practice can mean *before* a formal decision has been made by the operator to designate an event as an ''incident'' reported to PHMSA some time (as many as 30 days later) pursuant to §§ 191.9 or 191.15.

malfunctioning devices. This change ensures that operator's maintenance procedures ensure reliable overpressure protection and the minimization of emission from malfunctioning pressure relief devices. PHMSA's proposed language also identifies specific action operators would have to take on operation of a malfunctioning pressure relief device. PHMSA proposes to require a relief device be repaired or replaced immediately if it operates above the pressure limits in § 192.201(a) or § 192.739, fails to operate, or otherwise fails to provide reliable overpressure protection due to the potential consequences of overpressurizing the pipeline.

On the other hand, a relief device that activates below the intended set pressure poses a hazard to the environment, especially if it releases gas at normal operating pressure. Therefore, PHMSA also proposes that if a relief device activates below the set pressure range, the operator must take immediate and continuous action to stop the release of gas and ensure operation with an adequate margin to overpressure conditions. The device must then be repaired or replaced as soon as practicable, and within 30 days. Action to stop the flow of gas should be defined in an operator's abnormal operating procedures and could include reconfiguring the relief device.

In either case the operators would be obliged to maintain records documenting the proper operation and any remediation/replacement of pressure relief devices for the service life of their facilities.

PHMSA understands that its proposed requirements for design, configuration, and maintenance of pressure relief valves discussed above would be reasonable, technically feasible, cost-effective, and practicable for affected gas pipeline operators. PHMSA understands that some affected operators may already have adopted protocols ensuring that the design and configuration of pressure relief devices minimizes emissions of pressurized (natural, toxic, corrosive, or flammable) gases, either voluntarily (to minimize loss of commercially valuable commodities) or in response to State or Federal requirements. The NPRM would backstop those existing practices by enshrining them in regulation by prescribing release mitigation as a mandatory factor in the design and selection of new pressure relief devices; the NPRM contemplates operators would have flexibility within that broad objective to develop their precise implementation strategy for a particular (new) pressure relief device. Similarly, existing pressure relief device configurations would need to be tweaked to minimize releases as well, but only so far as such configurations can be changed; operators whose pressure relief devices do not admit changes in configuration would not have to effectuate any changes. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the NPRM's proposed compliance timelines—which are based on an effective date of six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to develop and implement compliance protocols and manage any related compliance costs.

H. Investigation of Failures—§ 192.617

Understanding the causes of pipeline leaks and reasons for malfunction of pressure relief devices is essential for identifying systemic threats to pipeline integrity and preventing similar failures in the future. Although PHMSA regulations at § 192.617 require operators of gas distribution, transmission, offshore gathering, and Type A gathering pipelines to have procedures for analyzing the causes of ''failures and incidents,'' [282] those requirements are limited in application (they do not apply to Types B and C gathering pipelines), and ''failure'' is not defined in part 192. With respect to the meaning of the term ''failure'', operators have applied the definition in the instructions for the Gas Transmission and Gas Gathering Pipeline System Annual Report,[283] which references the broad, functional definition in ASME B31.8, ''Gas Transmission and Distribution Piping Systems.'' ASME B31.8 defines a failure as the following:

failure: a general term used to imply that a part in service has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that it has become unreliable or unsafe for continued use.

Although PHMSA has issued interpretations suggesting that leaks caused by certain mechanisms (in particular, those resulting from corrosion) would require investigation pursuant to § 192.617,[284] PHMSA regulations do not require investigation of all failures that result in leaks. This limitation could prevent investigations that can identify systemic integrity threats to their pipelines—as well as denies PHMSA and State regulators information necessary to protect public safety and the environment.

PHMSA therefore proposes to address the lack of specificity of the definition of a failure by revising § 192.617 to define the term ''failure'' for the purposes of that section using language similar to that in ASME B31.8. This approach would facilitate compliance by leveraging elements of a consensus industry standard with which operators are familiar, and portions of which are incorporated by reference elsewhere in PHMSA regulations. Additionally, PHMSA already references ASME B31.8's functional definition of a failure in the instructions for gas transmission and regulated gathering pipeline annual reports. Since a leaking pipe has failed to contain gas, a failure that results in a leak would be required to be investigated in accordance with § 192.617. The proposed definition clarifying that all leaks on pertinent gas pipelines require investigation under § 192.617 would improve safety. The proposed changes are intended to complement the leak grading and repair requirements in this NPRM (as well as repair criteria and IM requirements elsewhere in PHMSA regulations) and equip operators, PHMSA, and State regulators with the information needed in developing proactive initiatives to avoid future pipeline failures. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects this proposed amendment will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the NPRM's proposed compliance timelines—which are based on an effective date of six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to develop

[282] PHMSA's discussion of § 192.617 describes the text of that provision as it will be amended on the October 5, 2022, effective date of the Valve Installation and Rupture Detection Final Rule.

[283] PHMSA Form F 7100.2–1 (revision 10–2021), Instruction Revision (10–2021). *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2021-10/Current%20GT%20GG%20Annual%20Instructions%20-%20PHMSA%20F%207100%202-1%20Approved%2010-2021%20for%20CY%202021%20and%20Beyond.pdf.*

[284] PHMSA, Interpretation Response Letter No. PI–92–033 (Jul. 16, 1992).

and implement compliance protocols and manage any related compliance costs.

Although PHMSA proposes to limit the scope of application of this revised definition of ''failure'' to § 192.617, it acknowledges that term is used elsewhere in PHMSA regulations. PHMSA therefore invites comment on whether the proposed definition of ''failure'' should instead be located within the broadly applicable definitions at § 192.3 (for potential inclusion within a final rule in this proceeding). Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of that approach, including whether that approach would be technically feasible, cost-effective, and practicable.

I. Type B and Type C Gathering Pipelines—§ 192.9

Types B and C gathering pipelines are not currently subject to all of the part 192 safety requirements broadly applicable to other part 192-regulated gas pipelines, including those pertaining to procedural manuals for operations, maintenance, and emergency response procedures (§ 192.605), patrolling (§ 192.705), and certain recordkeeping (§ 192.709); Type B gathering pipelines are also not subject to emergency planning requirements set forth in § 192.615. Further, because Types B and C gathering pipelines are not subject to § 192.605, some stakeholders have questioned whether those pipelines are excepted from the self-executing requirements within section 114 of the PIPES Act of 2020 for operators to have procedures to eliminate leaks, minimize releases of natural gas, and repair or remediate pipelines known to leak.[285] Additionally, most Type C gathering pipelines are, pursuant to § 192.9(f)(1), not even subject to PHMSA's minimal existing requirements for leakage surveys (§ 192.706) and repair of hazardous leaks (§ 192.703(c)).[286]

These limitations contribute to public safety and environmental risks. PHMSA has historically imposed each of the requirements listed in the preceding paragraph on gas transmission and Type A gathering pipelines precisely because of the self-evident, appreciable public safety benefits they entail.[287] Although PHMSA previously declined to extend those minimal requirements to Types B and C gathering pipelines (representing the majority of part 192-regulated gathering pipeline mileage),[288] the notable public safety and environmental risks from Types B and C gathering pipelines discussed throughout this NPRM warrant removal of those historic regulatory gaps. As described above in section II.C.2, incidents and leaks occur on Type B and Type C gathering pipelines just as they occur on Type A pipelines. For Type B lines, the public safety risks of any incident are evident due to the location of those pipelines in densely-populated Class 2, 3 and 4 locations, while the high operating pressures and large diameters of Type C pipelines entail risks to public safety similar to those posed by Type A pipelines (notwithstanding Type C lines' location in more sparsely-populated Class 1 areas than Type A lines).[289] And as explained above, leaks from any type of natural gas gathering pipeline contains VOCs and HAPs, exacerbating public safety and environmental risk. Leaks of unprocessed natural gas also contain corrosive materials that can accelerate leak degradation.[290] The public safety and environmental risks associated with releases (whether leaks or more serious incidents) from gas gathering pipelines also support extension of emergency planning requirements to Type B gas gathering pipelines, which are located in the vicinity of buildings intended for human occupancy; the emergency planning requirements at § 192.615 will ensure that those operators have in place a robust framework for proactive measures to mitigate the public consequences of any emergency on their systems. Lastly, increasing appreciation for the outsized contribution to climate change of fugitive and vented emissions from all natural gas gathering pipelines underscores the importance of minimizing those greenhouse emissions from Types B and C regulated gathering pipelines.

This NPRM therefore proposes a series of regulatory amendments representing a first step in mitigating the anomalous treatment of Types B and C gathering pipelines in PHMSA regulations. Specifically, PHMSA proposes to revise § 192.9 to add to the list of part 192 requirements applicable to Types B and C pipelines each of its proposed requirements for pressure relief device design and maintenance (§§ 192.199 and 192.773),[291] certain recordkeeping (§ 192.709) and procedural manual requirements for operations, maintenance, and emergency response (§ 192.605), and—for Type B gathering pipelines—the emergency planning requirements at § 192.615. Each of these requirements have proven utility in minimizing public safety and environmental risks from gas transmission and Type A gathering pipelines and exemplify common-sense programmatic elements that *any* responsible business owning facilities known to transport pressurized, hazardous commodities would maintain in ordinary course (even in the absence of explicit regulatory requirements) to protect public safety and the environment. Extension of the procedural manual requirements at § 192.605 and recordkeeping requirements at § 192.709, moreover, would facilitate regulatory oversight of Types B and C gathering facilities by PHMSA and State inspectors by aligning documentation requirements with existing substantive requirements under § 192.9. It would also dispel any uncertainty among stakeholders regarding application to Types B and C gathering pipelines of the self-executing obligations under section 114 of the PIPES Act of 2020 to eliminate leaks, minimize emissions, and repair or remediate pipelines known to leak based on their material, design, or operating and maintenance history. Extension of the emergency planning requirements in § 192.615 to Type B gathering pipelines would also improve public awareness of pipeline safety and emergency response to incidents on Type B gathering pipelines, bringing requirements for such pipelines in line with existing requirements for all other part 192-regulated gas pipelines. Effective emergency response requirements are critical to ensure the safety of the public, emergency responders, and operator personnel during gas pipeline emergencies on Type B gathering lines, which are located in Class 2, 3, and 4

[285] *See, e.g.,* GPA Midstream and American Petroleum Institute, ''Joint Comments re Docket No. PHMSA–2021–0039, Pipeline Leak Detection, Leak Repair and Methane Emission Reductions Public Meeting'' at 4–5 (May 24, 2021).

[286] PHMSA's RIA for the Gas Gathering Final Rule estimated only ca. 20,000 miles (of the ca. 90,000 total miles of Type C pipelines) would be subject to §§ 192.703 and 192.705. *See* Gas Gathering RIA at 15.

[287] PHMSA, ''Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards,'' 71 FR 13289, 13292 (Mar. 15, 2006).

[288] *See* Gas Gathering RIA at 15 (noting a total of ca. 90,000 miles of Type C gathering pipelines) *and* 30 (noting a total of ca. 11,000 miles of Types A and B gathering pipelines).

[289] *See* Gas Gathering Final Rule at 63267.

[290] Leaks from part 192-regulated gathering lines transporting flammable, toxic, or corrosive gases other than natural gas also entail their own safety and environmental risks.

[291] As explained elsewhere, PHMSA's proposed § 192.199 requirements would only apply to new, replaced, relocated, or changed Type C gathering pipelines.

locations.[292] Section 192.615 includes requirements to ensure effective emergency preparedness, including a coordinated operator and community response to pipeline emergencies. Moreover, this requirement would ensure that operators of Type B gathering lines are prepared to take appropriate immediate and continuous actions in response to a grade 1 leak, which could require activation of an emergency response plan. PHMSA further proposes (as discussed above) to extend the suite of enhanced leak detection and repair-related proposals elsewhere in this NPRM to certain Types B and C gathering pipelines (including §§ 192.703(c) and (d), 192.705, 192.706, 192.709, 192.760, 192.763, and 192.769). Similarly, PHMSA also proposes to extend requirements for this NPRM's elements pressure relief device maintenance (§ 192.773) to Types B and C gathering pipelines to further reduce emissions and public safety and environmental risks associated with Types B and C gathering pipelines.

PHMSA expects the above proposed first steps toward improving alignment of regulatory requirements for Types B and C gas gathering pipelines with those applicable to other part 192-regulated pipelines would be reasonable, technically feasible, cost-effective, and practicable. The specific regulatory requirements PHMSA proposes to extend are common-sense, widely-employed approaches adopted by reasonably prudent operators in ordinary course to minimize losses of commercially valuable commodities and risks to public safety and the environment from the operation of pipelines transporting pressurized (natural, corrosive, toxic, or flammable) gases. Precisely for that reason, PHMSA expects that some Types B and C gas gathering pipeline operators may already voluntarily comply with those proposed requirements. Those and other operators of Types B and C gas gathering pipelines (some of which operators may also operate either gas transmission or Type A gathering pipelines) may also have pipelines within their systems subject to similar procedural manual, recordkeeping, and pressure relief device requirements under Federal or State law; those existing procedural manuals and (recordkeeping and pressure relief device design and configuration) protocols could be extended and adapted to Types B and C gas gathering pipelines. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the proposed compliance timelines—based on an effective date of the proposed requirements six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite changes to existing procedural manuals and protocols (and conduct any accompanying personnel training) and manage any related compliance costs.

PHMSA solicits comment on additional opportunities to harmonize part 192 treatment of regulated gathering pipelines for potential inclusion within a final rule in this or a subsequent rulemaking proceeding. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

J. Miscellaneous Changes in Parts 191 and 192 To Reflect Codification in Federal Regulation of the Congressional Mandate To Address Environmental Hazards of Leak From Gas Pipelines

As discussed above in section II.D, current PHMSA regulations reflect an ambiguous distinction between ''hazardous'' and other leaks that reflects PHMSA's historical prioritization of public safety hazards. PHMSA's regulations at parts 191 and 192 consequently contain numerous references to ''potentially hazardous'' gas releases, or to ''hazards'' expressed principally in terms of public safety risks. As discussed above in sections II.D.3, III.C.1, and III.C.6, 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. PHMSA therefore proposes miscellaneous conforming revisions to various provisions of parts 191 and 192 consistent with the PIPES Act of 2020's direction. PHMSA proposes to define ''hazardous leak or leak'' in § 192.3 and apply it to those subparts of part 192 other than the IM regulations under subparts O and P. That proposed definition would make ''hazardous leak'' synonymous to ''leak.'' PHMSA also proposes to delete language in several places in part 192 suggesting contingency (for example, references to ''*potentially* hazardous'' releases) at each of §§ 192.503(a)(2), 192.507(a), 192.509(a), 192.513(b), 192.553(a)(2), 192.557(b)(2), and 192.751(a)) regarding hazards posed by releases from gas pipelines.[293] For other provisions (specifically, §§ 192.605(b)(9), 192.613(b), 192.615(a), 192.615(a) introduction, 192.616(d)(2) and (j)(2), and 192.703(c)), existing language referring to ''hazard'' and ''hazardous leak'' is elastic enough to accommodate PHMSA's proposed expansion of the ''hazard'' concept to encompass environmental hazards without revision of regulatory text. Although the expansion of the ''hazard'' concept may require some operators to modify procedures and practices, PHMSA expects any compliance burdens would be de minimis because a reasonably prudent operator would employ practices and procedures addressing the need to minimize releases of natural gas and other environmental harms from their activities. In addition, the mechanism for public safety and environmental harms (the release of gas from a pipeline) is the same.

This proposed expansion of ''hazardous leaks'' to encompass hazards to the environment and public safety could lead operators to modify testing practices. For example, PHMSA's proposed changes to subpart J testing requirements (specifically, §§ 192.503(a)(2), 192.507(a), 192.509(a), 192.513(b)) to limit placement into service of any new, replaced, relocated or otherwise changed gas transmission, distribution, offshore gathering, Types A, B, and C gathering pipeline segments with *any* leak could make testing and qualification of new, replaced, relocated, or changed pipelines more difficult in that it would require conforming revisions to operator acceptance criteria. However, PHMSA expects the impact of those proposed revisions would be *de minimis,* as reasonably prudent operators would not place new, replaced, relocated, or changed pipeline segments into service

[292] Type B gathering pipelines are defined in § 192.8 as those gathering pipelines located in Class 4, Class 3, and certain Class 2 locations with the operating characteristics specified in Table 1 to § 192.8(c)(2).

[293] PHMSA will also propose conforming revisions to the part 191 annual report forms and instructions for each of gas transmission, offshore gathering and Types A, B, and C gathering pipelines (F7100.2–1), Type R gas gathering pipelines (F7100.2–3), and gas distribution pipelines (F7100.1–1) to eliminate distinctions made or suggested in those documents between hazardous leaks, other leaks, or other gas releases allegedly too small to merit reporting.

if they had observed *any* leak during initial testing. The same logic would extend to its proposed amendment of uprating requirements (at §§ 192.553(a)(2), 192.557(b)(2)) applicable to gas transmission, distribution, offshore gathering, and Type A gathering pipelines.

PHMSA does not propose to expand every reference to ''hazard'' or ''hazardous leak'' in PHMSA's part 191 and 192 regulations to encompass environmental hazards. First, PHMSA proposes to exclude the IM regulations at subparts O and P from application of the new definition of ''leak or hazardous leak'' at § 192.3 to keep operator IM plans—and operators' limited resources implementing those plans—focused on identification and management of public safety risks.[294] PHMSA is proposing to revise § 192.1007 to delete a reference to § 192.703(c) that would be rendered obsolete by the limited application of PHMSA's proposed definition of ''leak or hazardous leak'' at § 192.3. Second, PHMSA is not proposing to refer to ''hazards'' or leaks ''hazardous to public safety'' where an explicit reference to environmental hazards would either be unnecessary (*e.g.,* because other subparagraphs within the same provision would address any environmental hazards) or inapposite to the pertinent requirement. This applies to §§ 192.605(c)(1)(v), 192.605(a)(6) and (7), 192.615(c), and 192.721. Similarly, PHMSA proposes to revise other references to (unqualified) ''hazards'' to preserve those provisions' historical and appropriate focus on public safety, rather than environmental, hazards. Generally, those proposed regulatory amendments would consist of addition of qualifying language (''hazard(s) *to public safety*'') where an explicit reference to environmental hazards would either be unnecessary (*e.g.,* because other, related provisions or paragraphs would address any environmental hazards) or inapposite to the pertinent requirement. PHMSA proposes these conforming amendments for §§ 191.23(a)(9), 192.167(a)(2), 192.169(b), 192.179(c), 192.199(e), 192.361(f)(3), 192.363(c), 192.629(a) and (b), 192.727(b) and (c) and 192.751. Third, even though PHMSA does not propose to expand the concept of ''hazard'' uniformly across its regulations, operators nevertheless may voluntarily supplement the baseline requirements of PHMSA regulations by explicitly incorporating environmental harms from releases of gas from their pipelines throughout their policies, procedures, and practices.

PHMSA expects no material impact on operators' existing practices from the above proposed new definition (along with the limited, conforming revisions specified above), which supports a conclusion that those proposed amendments would be reasonable, technically feasible, cost-effective, and practicable. PHMSA invites comment by stakeholders on the appropriateness of each of its above proposed revisions to, or preservation of, existing regulatory references to ''hazards'' and ''hazardous leaks'' for potential modification of its above proposed amendments in any final rule issued in this proceeding. PHMSA also solicits comment on whether any provisions not addressed above would also benefit from conforming revision. Should stakeholders proffer alternative or additional regulatory amendments, they should support those proposals by reference to each of any expected safety and environmental benefits, as well as the cost-effectiveness, practicability, and technical feasibility.

V. Section-By-Section Analysis

§ 191.3 Definitions

PHMSA proposes to revise § 191.3 to add a definition for large-volume gas releases that must be reported, per the new § 191.19. PHMSA proposes to define a ''large-volume gas release'' as an intentional or unintentional release of gas of 1 MMCF or more. This new large-volume gas release reporting requirement would be applicable to all gas pipeline facility operators, including (but not limited to) operators of jurisdictional underground storage and LNG facilities, as well as Type R gas gathering pipelines.

PHMSA also proposes revision of the property damage criterion within the definition of ''incident'' to exclude certain indirect costs associated with the cost incurred by operators in conducting repair activity. In particular, the revised definition excludes the cost of preparing and obtaining permits, as well as the removal and replacement of third-party infrastructure that was not itself damaged by the event. For example, if a release from a pipeline beneath a street did not damage a roadway, but pavement must be temporarily removed to repair the pipeline, the costs of the roadway repair and associated permits would not be included in the definition of property damage.

§ 191.11 Distribution System: Annual Report

PHMSA proposes to change Form F7100.1–1 and its instructions to collect data on leaks detected and repaired by grade in the annual reporting period and the number (by grade) of unrepaired leaks at the conclusion of the annual reporting period. PHMSA also proposes to change the gas distribution annual report form to include estimated aggregate emissions from leaks by grade and other emissions categorized by source category (similar to those in the tables in section II.C) on an operator's system over the annual reporting period. PHMSA also proposes to revise miscellaneous sections of those annual reports and their instructions to remove statements expressing or suggesting that releases that can be eliminated by routine maintenance (such as lubrication, tightening, or adjustment) need not be reported as leaks. Such leaks and leak repairs would instead be recorded as a separate line item similar to the existing collection related to mechanical fitting failures to ensure a complete accounting of the number of releases from gas distribution pipelines.

§ 191.17 Transmission Systems; Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities; Annual Report

PHMSA proposes to change the gas transmission and regulated gathering annual report form (Form F7100.2–1) and its instructions to collect data on leaks detected and repaired by grade during the annual reporting period. This form change is applicable to gas transmission, offshore gas gathering, and Type A, B, and C regulated onshore gas gathering pipelines. PHMSA also proposes to change Form F7100.2–1 to include estimated aggregate emissions from leaks by grade and other emissions by source category from an operator's system over the annual reporting period. PHMSA does not propose changes to the Type R annual report form (Form F7100.2–3). Lastly, PHMSA proposes to revise miscellaneous sections of the annual reports (and accompanying instructions) for each of gas transmission, offshore gathering, and regulated onshore gathering pipelines (Form F7100.2–1), Type R gathering pipelines (Form F7100.2–3) and LNG facilities (Form F7100.3–1) to remove statements expressing or suggesting that releases that can be eliminated by routine maintenance (such as lubrication, tightening, or adjustment) need not be reported as leaks. A count of leaks eliminated by routine

[294] Similarly, this proposed definition would not apply to IM programs for UNGSFs, which are not subject to any requirements of part 192 aside from § 192.12(d).

maintenance would instead be reported as a separate line item on the annual report form.

§ 191.19 Large-Volume Gas Release Reports

PHMSA proposes to create a new § 191.19 requiring operators to submit reports of large-volume gas releases. Like incident reports, this requirement would be applicable to all operators of PHMSA-jurisdictional gas pipeline facilities, including operators of jurisdictional underground storage and LNG facilities, as well as Type R gas gathering pipelines. The term ''large-volume gas release'' is defined in proposed amendments to § 191.3, as described above. The report would be required for releases that become reportable on or after the effective date of a final rule.

The new proposed report would require pertinent operators to report both intentional and unintentional releases of 1 MMCF or more of gas. This new form would capture both unintentional, fugitive emissions (*e.g.,* from leaks) as well as blowdowns, maintenance related venting, pressure relief device actuations, and other intentional, vented emissions. Operators would be required to submit a report within 30 days from the date that a release known at detection to be 1 MMCF or more was detected, or 30 days from the date that a previously detected release became reportable. If the time the leak started is unknown, operators should base the calculation based on estimated release volume from the date of the most recent leakage survey.

PHMSA also notes that events reported as incidents under §§ 191.9 or 191.15 would not also need to be reported pursuant to the proposed § 191.19 unless the total release volume at cessation exceeds 10% of the volume estimated in the incident report. If an unintentional release reported as a large-volume gas release report subsequently becomes reportable as an incident due to updated release volume estimates or consequences (or for any other reason), the operator would have to resubmit it as an incident report appropriate for the facility type.

§ 191.23 Reporting Safety-Related Conditions

Consistent with PHMSA's current treatment of releases reportable as incidents, PHMSA proposes to except large-volume gas releases as defined in proposed § 191.3 from the requirement to submit a safety-related condition report pursuant to § 191.23. PHMSA also proposes to amend § 191.23(a)(9) to explicitly limit that safety-related condition reporting requirement to imminent hazards to public safety.

§ 191.29 National Pipeline Mapping System

PHMSA proposed to delete the current exemption for offshore gas gathering, and Types A, B, and C gathering pipelines from NPMS reporting requirements at § 191.29(a), thereby obliging operators of those pipelines to submit geospatial pipeline location data to NPMS. PHMSA does not propose to require operators of Type R, reporting-only, gas gathering lines to participate in the NPMS.

§ 192.3 Definitions

Section 192.3 defines a number of terms that are referenced in part 192. PHMSA proposes to add a few definitions, primarily those associated with leak detection and repair. These are primarily referenced in proposed § 192.760 for the purposes of leak grading and repair requirements.

PHMSA proposes to define 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 would include vaults, catch basins, and manholes. Unlike a building, a confined space is not ordinarily occupied for residential, commercial, or industrial uses. The difference between a confined space and a substructure is that a confined space is large enough to accommodate a person, while a substructure is not. Consistent with the GPTC Guide, this definition differs from the definition of a ''confined space'' used by OSHA at 29 CFR 1910.146(b).

PHMSA proposes to define a ''*gas-associated substructure*'' as a substructure that is part of an operator's pipeline facility but that is not itself designed to convey or store gas. These would typically consist of small vaults for devices, such as valves, meters, regulators, or other equipment.

PHMSA proposes to define a ''*substructure*'' as any subsurface structure that is not large enough for a person to enter and in which gas could accumulate or migrate. Substructures would include telephone and electrical service boxes and associated ducts and conduits, valve boxes, and meter boxes.

PHMSA proposes to define, for the purposes of all subparts of part 192 other than IM requirements in § 192.12(d) and subparts O and P, a ''*leak or hazardous leak*'' 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 (including operating personnel), property, or the environment, or any uncontrolled release of gas from a pipeline that is detectable via equipment, sight, sound, smell, or touch. PHMSA proposes to require that each leak must be investigated, graded, and repaired in accordance with proposed § 192.760. This includes leaks that are identified by the public or emergency personnel. Leaks include unintended releases through intended release pathways. For example, a pressure relief device or emergency shutdown device that fails and releases gas through a vent or flare is a leak.

PHMSA proposes to define the ''*lower explosive limit (LEL)*'' as the minimum concentration of vapor in air below which propagation of a flame does not occur in the presence of an ignition source at ambient temperature and pressure. The LEL of natural gas is 5% methane in air by volume. The LEL for propane is 2.1% propane in air by volume. The LEL for hydrogen gas is 4% hydrogen by volume.

PHMSA proposes to define a ''*tunnel*'' as a subsurface passageway large enough for a person to enter and in which gas could accumulate or migrate. Compared with a confined space, a tunnel is intended for regular or occasional human occupancy.

PHMSA proposes to define a ''*wall-to-wall paved area*'' as an area where the ground surface between the curb of a paved street and the front wall of a building is continuously paved with hard top surface impermeable to gas, excluding non-continuous landscaping such as tree plots.

§ 192.9 What requirements apply to gathering lines?

The NPRM proposes a series of amendments to § 192.9 to improve protection of public safety and the environment from leaks and incidents on all part 192-regulated onshore and offshore gathering lines, and to improve alignment between the part 192 safety requirements applicable to each of Types A, B, and C gathering pipelines.

Requirements for Type A gathering pipelines are defined in § 192.9(c), which requires that a Type A pipeline comply with the requirements of part 192 for transmission lines, subject to specific exceptions listed in that paragraph. PHMSA proposes no change to that paragraph. All Type A gathering pipelines would therefore be subject to the proposals introduced within the NPRM for transmission lines, including each of the following: revised definitions, to include a definition of ''leak or hazardous leak'' to account for environmental hazards in connection with non-IM subparts of part 192 (§ 192.3); engineering analyses for the design of pressure relief devices (§ 192.199); modification of initial testing requirements to account for environmental hazards (§§ 192.503, 192.507, 192.509, and 192.513); modification of procedural manuals to provide for elimination of leaks and minimize releases of gas as well as remediation or replacement of pipelines known to leak (§ 192.605); revision of failure investigation procedures for investigation of leaks (§ 192.617); enhanced patrolling requirements (§ 192.705); enhanced leakage survey requirements (§ 192.706); new leak grading, repair, and documentation requirements (§§ 192.703(c) and (d), 192.709, 192.760 and 192.763); new limitations on uprating pipelines (§§ 192.553 and 192.557); new leak detection personnel qualification requirements (§ 192.769); specific requirements for minimization of blowdown emissions (§ 192.770), and new pressure relief device maintenance requirements (§ 192.773). PHMSA also proposes that Type A gathering pipeline operators would be able to submit for PHMSA review a notification pursuant to § 192.18 for flexibility with respect to each of the following: use of alternative leak detection equipment in non-HCA, Class 2 locations in complying with § 192.706; use of an alternative performance standard in Class 2 locations in complying with § 192.763; and extension of leak repair timelines set forth in § 192.760.

Part 192 requirements for Type B gathering pipelines are listed in § 192.9(d); part 192 requirements not listed in § 192.9(d) are generally inapplicable to Type B gathering pipelines. With respect to new, relocated, replaced, or otherwise changed Type B gathering lines, PHMSA proposes (consistent with its proposals for other regulated gathering lines) each of the following: a new § 192.199 prescribing engineering analyses for the design of pressure relief devices; and modification of initial testing requirements to account for environmental hazards (§§ 192.503, 192.507, 192.509, and 192.513). PHMSA also proposes to revise § 192.9(d) to add to the list of part 192 operations (subpart L) and maintenance (subpart M) requirements applicable to all Type B gathering pipelines a number of requirements for enhancing Type B operator leak detection, grading and repair programs, including the following: revised definitions, to include a definition of ''leak or hazardous leak'' to account for environmental hazards in connection with non-IM subparts of part 192 (§ 192.3); introduction of procedural manuals providing for, among other things, the elimination of leaks and minimizing releases of gas as well as remediation or replacement of pipelines known to leak (§ 192.605); patrolling requirements (§ 192.705); enhanced leakage survey requirements (§ 192.706); new leak grading, repair, and documentation requirements (§§ 192.703(c) and (d), 192.709, 192.760 and 192.763); and new pressure relief device maintenance requirements (§ 192.773). PHMSA has not proposed that operators of Type B gathering pipelines would be subject to new vented emissions mitigation requirements at proposed § 192.770. Further, PHMSA's proposed revision referencing § 192.605 procedural manual requirements would dispel any stakeholder confusion regarding whether Type B gathering pipelines are subject to the self-executing requirements at section 114 of the PIPES Act of 2020 to eliminate leaks, minimize releases of natural gas, and remediate or replace pipelines known to leak. PHMSA also proposes that Type B gathering pipelines would be subject to emergency response manual documentation requirements at § 192.605 and emergency planning requirements at § 192.615. Under § 192.605(b)(1) and (b)(2), operators must include procedures for compliance with the subpart M and subpart I requirements applicable to the Type B lines in accordance with § 192.9, but they are not required to have procedures for other subparts M and I requirements. Similarly, operators of Type B gathering lines are not required to have procedures for complying with § 192.631 control room management requirements referenced in § 192.605(b)(12), nor for the continuing surveillance and accident investigation requirements referenced in § 192.605(e). Additionally, PHMSA proposes that Type B gathering pipeline operators would be able to submit for PHMSA review a notification pursuant to § 192.18 for flexibility with respect to each of the following: use of alternative leak detection equipment in non-HCA, Class 2 locations in complying with § 192.706; extension of leak repair timelines set forth in § 192.760; and use of an alternative performance standard in Class 2 locations in complying with § 192.763.

PHMSA also proposes a number of revisions to § 192.9 paragraphs identifying specific part 192 requirements applicable to Type C gathering pipelines to promote alignment with regulatory requirements applicable to other regulated onshore gathering pipelines and reduce fugitive and vented emissions. Specifically, PHMSA proposes to revise § 192.9(e) to expand the list of part 192 operations (subpart L) and maintenance (subpart M) requirements applicable to all Type C gathering pipelines to include a number of requirements to enhance Type C operator leak detection, grading and repair programs, including the following: revised definitions, to include a definition of ''leak or hazardous leak'' to account for environmental hazards in connection with non-IM subparts of part 192 (§ 192.3); procedural manuals providing for, among other things, elimination of leaks and minimize releases of natural gas as well as remediation or replacement of pipelines known to leak (§ 192.605); patrolling requirements (§ 192.705); enhanced leakage survey requirements (§ 192.706); new leak grading, repair, and documentation requirements (§§ 192.703(c) and (d), 192.709, 192.760 and 192.763); and pressure relief device maintenance requirements (§ 192.773). PHMSA also proposes that new, replaced, relocated, or changed Type C gathering lines would be subject to the pressure relief device design and configuration requirements at § 192.199, as well as modification of initial testing requirements to account for environmental hazards (§§ 192.503, 192.507, 192.509, and 192.513). PHMSA has not proposed that operators of Type C gathering pipelines would be subject to its proposed new limitations on uprating pipelines at §§ 192.553 and 192.557, or the vented emissions mitigation requirements at proposed § 192.770. PHMSA also proposes revision to § 192.9(f)(1) to narrow the exceptions identified in that subparagraph to ensure that all Type C gathering pipelines are subject to leakage survey and repair requirements. Further, PHMSA's proposed revision referencing § 192.605 procedural manual documentation requirements would dispel any stakeholder confusion regarding whether Type C gathering pipelines must have emergency response manuals, or are subject to the self-executing requirements at section 114 of the PIPES Act of 2020 to eliminate leaks, minimize releases of natural gas, and replace or remediate pipelines known to leak. Under § 192.605(b)(1) and (b)(2), operators must include procedures for compliance with the subpart M and subpart I requirements applicable to the Type C pipeline in accordance with § 192.9, but they are not required to have procedures for other subparts M and I requirements. Similarly, operators are only required to have procedures for submitting safety-related condition reports on Type C gathering lines if the pipeline is subject to the safety-related condition reporting requirement in § 191.23 (*i.e.,* the pipeline is required to have an MAOP). Further, operators of Type C gathering lines are not required to have procedures for complying with § 192.631 control room management requirements referenced in § 192.605(b)(12), nor for the continuing surveillance and accident investigation requirements referenced in § 192.605(e). PHMSA also proposes that Type C gathering pipeline operators would be able to submit for PHMSA review a notification pursuant to § 192.18 for flexibility in each of the following: use of alternative leak detection equipment in non-HCA, Class 1 locations in complying with § 192.706; use of an alternative performance standard in Class 1 locations in complying with § 192.763; and extension of leak repair timelines set forth in § 192.760.

Lastly, PHMSA proposes minor changes to the language in § 192.9(b) listing part 192 requirement to which offshore gas gathering pipelines are exempt: specifically, PHMSA has added language stating explicitly that offshore gas gathering pipelines would be exempt from the default grade 2 classification requirement and at § 192.763(c)(1)(vi) and the 30-day repair requirement at § 192.763(c)(3). PHMSA has not otherwise proposed to modify § 192.9(b). However, because PHMSA is proposing a number of revisions to part 192 requirements applicable to gas transmission lines, those proposed requirements would apply to offshore gathering pipelines as well pursuant to § 192.9(b). Specific proposals that would apply to offshore gathering pipelines include each of the following: revised definitions, to include a definition of ‘‘leak or hazardous leak’’ to account for environmental hazards in connection with non-IM subparts of part 192 (§ 192.3); engineering analyses for the design of pressure relief devices (§ 192.199); modification of initial testing requirements to account for environmental hazards (§§ 192.503, 192.507, 192.509, and 192.513); new limitations on uprating pipelines (§§ 192.553 and 192.557); modification of procedural manuals to provide for elimination of leaks and minimize releases of gas as well as remediation or replacement of pipelines known to leak (§ 192.605); revision of failure investigation procedures for investigation of leaks (§ 192.617); enhanced patrolling requirements (§ 192.705); enhanced leakage survey requirements (§ 192.706); new leak grading, repair, and documentation requirements (§§ 192.703(c) and (d), 192.709, 192.760 and 192.763); new leak detection personnel qualification requirements (§ 192.769); specific requirements for minimization of blowdown emissions (§ 192.770), and new pressure relief device maintenance requirements (§ 192.773). PHMSA also proposes that offshore gas gathering pipeline operators would be able to submit for PHMSA review a notification pursuant to § 192.18 for flexibility with respect to each of the following: use of an alternative ALDP performance standard in complying with § 192.763; and extension of leak repair timelines set forth in § 192.760. PHMSA has not proposed that offshore gas gathering pipelines would be subject to its proposed default requirement within § 192.763 for any leak be considered a grade 2 leak at a minimum.

§ 192.12 Underground Natural Gas Storage Facilities

Section 192.12(c) obliges operators of underground natural gas storage facilities to have and follow written procedures for operations, maintenance, and emergency response activities. PHMSA proposes to revise the regulatory language in this provision to incorporate within its regulations the section 114 of the PIPES Act of 2020 self-executing mandate that operators update their procedures to provide for the elimination of leaks and minimize release of gas from pipeline facilities.

§ 192.18 How To Notify PHMSA

PHMSA proposes to revise § 192.18(c) to cross reference proposed amendments in the NPRM that allow an operator flexibility in complying with certain part 192 requirements. Specifically, the NPRM proposes to allow operators to use alternative compliance approaches with advance notification to PHMSA in connection with the following requirements: use of leak detection equipment for leakage surveys on onshore gas transmission and certain regulated gathering pipelines (§ 192.706(a)(2)); for each of natural gas transmission and gathering operators with pipelines in Class 1 or 2 locations, as well as operators of any part 192-regulated gas pipeline transporting gas other than natural gas, implementation of an alternative ALDP performance standard as well as alternative leak detection equipment (§ 192.763(c)); and minimum leak repair schedules (§ 192.760(h)). Each of these flexibilities is described separately under its respective discussion in this section V. As specified in existing § 192.18, an operator must notify PHMSA 90 days in advance of using an alternative compliance approach and may begin to use that alternative approach if they do not receive a letter after 90 days objecting to that alternative compliance approach from PHMSA.

§ 192.167 Compressor Stations: Emergency Shutdown

PHMSA proposes to revise § 192.167(a)(2) governing on new, replaced, relocated, or otherwise changed compressor stations on gas transmission and part 192-regulated onshore gas gathering pipelines to state that blowdowns of those facilities during emergency shutdowns must be directed toward locations where the released gas would not create a hazard to *public safety* specifically.

§ 192.169 Compressor Stations: Pressure Limiting Devices

PHMSA proposes to revise § 192.169(b) governing on new, replaced, relocated, or otherwise changed gas compression stations on gas transmission pipelines and boosting stations on part 192-regulated gathering pipelines to state that vent lines from pressure relief devices must exhaust gas to locations that would not create a hazard to public safety specifically.

§ 192.179 Transmission Line Valves

PHMSA proposes to revise § 192.179(c) governing blowdown valves on new, replaced, relocated, or otherwise changed gas transmission and Types A, B, and C gathering pipelines to state that the discharges from those valves must be located such that blowdowns to atmosphere would not create a hazard to public safety specifically.

§ 192.199 Requirements for Design and Configuration of Pressure Relief and Limiting Devices

PHMSA proposes to revise § 192.199 to require that all new, replaced, relocated, or otherwise changed overpressure protection devices be designed and configured to minimize unnecessary releases of gas to the atmosphere. Since § 192.199 is a generally applicable design requirement, this proposed amendment would apply to all facilities regulated under part 192, including gas transmission, distribution, offshore gas gathering, and Types A, B, and C onshore gas gathering pipelines. This requirement would not be retroactive, and thus would not apply to any pressure relief device on pipelines existing on or before the effective date of the rule unless the pipeline is subsequently replaced, relocated, or otherwise changed.

To comply with this proposed requirement, each pressure relief device must be designed and configured based on a documented engineering analysis demonstrating that the set and reset conditions of the device, as well as the size and configuration of it and its associated piping, are appropriate for providing adequate overpressure protection. Additionally, the design and materials used for the relief device must be compatible with the composition of the gas being transported and be suitable for the anticipated operating and environmental conditions. The design of the relief device would need to include isolation valves to support testing and maintenance.

Lastly, PHMSA proposes revision of § 192.199(e) to require that all new, replaced, relocated, or otherwise changed pressure relief and limiting devices on gas transmission, distribution, offshore gas gathering, and Types A, B, and C gas gathering pipelines would need to have discharge stacks, vents, or outlet ports located where gas can be discharged into the atmosphere without undue hazards to public safety specifically.

§ 192.361 Service Lines: Installation

PHMSA proposes revision of § 192.631(f)(3) governing new, replaced, relocated, or otherwise changed underground service lines installed under buildings to provide that vents from service line annular spaces must be to locations that would not create a hazard to public safety specifically.

§ 192.363 Service Lines: Valve Requirements

PHMSA proposes revision of § 192.363(c) governing design and construction requirements for valves on high-pressure service lines to limit that requirement to, among other things, certain high-pressure service lines installed in areas where blowdowns of gas would be hazardous to public safety specifically.

§ 192.503 General Requirements

PHMSA proposes to revise § 192.503(a)(2) governing initial testing requirements on new, replaced, relocated, or otherwise changed gas transmission, distribution, and part 192-regulated gathering pipelines to delete the qualification ''potentially'' modifying ''hazardous leak'' in recognition of the certainty of environmental harms from any released natural gas, flammable gas, toxic gas, or corrosive gas.

§ 192.507 Test Requirements for Pipelines To Operate at a Hoop Stress Less Than 30 Percent of SMYS and at or Above 100 p.s.i. (689 kPa) Gage

PHMSA proposes to revise § 192.507(a) governing certain initial testing requirements on new, replaced, relocated, or otherwise changed gas transmission, distribution, and part 192-regulated gathering pipelines to delete the qualification ''potentially'' modifying ''hazardous leak'' in recognition of the certainty of environmental harms from any released gas.

§ 192.509 Test Requirements for Pipelines To Operate Below 100 p.s.i. (689 kPa) Gage

PHMSA proposes to revise § 192.509(a) governing initial testing requirements on new, replaced, relocated, or otherwise changed gas transmission, distribution, and part 192-regulated gathering pipelines (other than service and plastic pipelines) to delete the qualification ''potentially'' modifying ''hazardous leak'' in recognition of the certainty of environmental harms from any released gas.

§ 192.513 Test Requirements for Plastic Pipelines

PHMSA proposes to revise § 192.513(b) governing initial testing requirements on new, replaced, relocated, or otherwise changed plastic gas transmission, distribution, and part 192-regulated gathering pipelines to delete the qualification ''potentially'' modifying ''hazardous leak'' in recognition of the certainty of environmental harms from any released gas. PHMSA also proposes an editorial correction of the word ''insure'' to ''ensure.''

§ 192.553 General Requirements

PHMSA proposes to revise the general requirements for uprating to clarify that any hazardous leaks detected during the uprating process on gas transmission, distribution, offshore gathering, and Type A gathering lines must be repaired prior to further increasing the pressure of the pipeline during the incremental pressure increase procedure in § 192.553(a). This requirement would apply to any gas transmission, distribution, or Type A gathering pipeline subjected to an incremental increase in operating pressure as described in § 192.553.

§ 192.557 Uprating: Steel Pipelines to a Pressure That Will Produce a Hoop Stress Less Than 30 Percent of SMYS: Plastic, Cast Iron, and Ductile Iron Pipelines

PHMSA proposes to revise § 192.557(b)(2) to require that operators of gas transmission, distribution, offshore gathering, and Type A gathering pipelines repair any hazardous leaks (note that PHMSA proposes to define leaks and hazardous leaks identically in § 192.3) that are found prior to uprating a pipeline that will operate at an MAOP producing a hoop stress less than 30 percent of SMYS, or that is made of plastic, cast iron, or ductile iron. A pipeline with an active leak would therefore not be permitted to be uprated to a higher MAOP until each leak repair was complete.

§ 192.605 Procedural Manual for Operations, Maintenance, and Emergencies

Existing § 192.605 requires each operator of an onshore or offshore gas transmission pipeline, gas distribution pipeline, offshore gas gathering pipeline, or Type A gas gathering pipeline to prepare and follow a written procedure manual for operations, maintenance, and emergency response activities. PHMSA proposes to revise § 192.9 to extend those procedural documentation requirements to Types B and C gas gathering pipelines, excluding requirements for procedures that are not applicable to such pipelines. PHMSA also proposes to revise § 192.605 to incorporate the self-executing mandate at section 114 of the PIPES Act of 2020 that the maintenance and operating procedures for part 192-regulated gas pipelines must include procedures for each of the elimination of leaks and for minimizing releases of gas from pipelines, as well as the remediation or replacement of pipelines known to leak based on their material, design, or past maintenance and operating history. These proposed amendments to §§ 192.9 and 192.605 would dispel any stakeholder uncertainty regarding application of the self-executing requirements in section 114 of the PIPES Act of 2020.

§ 192.617 Investigation of Failures

For the purposes of the existing requirement to investigate failures, PHMSA proposes to define the term ''failure'' for the purposes of § 192.617 to mean ''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.'' PHMSA considers any leaking gas pipeline as having failed to perform its intended function. This proposed regulatory amendment would apply to gas distribution, gas transmission, offshore gas gathering, and Type A regulated onshore gas gathering pipelines.

§ 192.629 Purging of Pipelines

PHMSA proposes to revise its provisions governing the purging of gas from each of gas transmission, distribution, offshore gathering and Type A gathering pipelines to clarify that this provision remains focused on addressing risks to public safety associated with purging of gas from those pipelines. PHMSA also proposes editorial amendments replacing the term ''released'' with ''introduced'' to more accurately reflect that gas is being injected into the pipeline and replacing the term ''line'' with ''pipeline.''

§ 192.703 General

As discussed above and below, PHMSA is proposing to delete the historical reference to ''hazardous leak'' in § 192.703 (which qualification limited the general repair requirement in that provision) and replace it with a reference to PHMSA's proposed § 192.760 leak grading and repair requirements. PHMSA's proposed revisions to §§ 192.703 (when coupled with proposed amendments to § 192.9) would extend the scope of the § 192.703 general leak repair requirement to all part-192 regulated gas pipelines.

PHMSA also proposes an exception from proposed requirements listed in § 192.703(d) for gas transmission compression and gathering boosting stations subject to EPA methane emissions monitoring and repair requirements within current 40 CFR part 60, subpart OOOOa regulations; proposed subpart OOOOb updates and subpart OOOOc methane emissions guidelines (as implemented through EPA-approved State plans with standards at least as stringent as EPA's emission guidelines in subpart OOOOc or implemented through a Federal plan).[295] Specific proposed requirements from which eligible stations would be excepted include the following: leak repair (§ 192.703(c)), leakage survey and patrol (§§ 192.705 and 192.706), leak grading and repair (§ 192.760), ALDPs (§ 192.763), and qualification of leak detection personnel (§ 192.769).

§ 192.705 Transmission Lines: Patrolling

Visual right-of-way patrols with or without the use of leak detection equipment are required by § 192.705 on gas transmission lines and are an important supplement to leakage surveys. PHMSA proposes to increase the minimum required frequency of right-of-way patrols on gas transmission, offshore gathering, and Type A gathering pipelines to at least 12 times each calendar year, with intervals between patrols not exceeding 45 days, regardless of location. PHMSA also proposes to revise § 192.9 to require operators perform patrols of Type B and Type C regulated onshore gas gathering pipelines on the same interval. An operator may combine a patrol pursuant to § 192.705 with a leakage survey pursuant to § 192.706, provided their procedures include both a visual survey of the right-of-way and a leakage survey with leak detection equipment.

§ 192.706 Transmission Lines: Leakage Surveys

PHMSA proposes to revise § 192.706 to increase the minimum frequency for performing leakage surveys of gas transmission, offshore gas gathering, and Types A, B, and C gathering pipelines, each located in HCAs in Class 1, Class 2, and Class 3 locations, to twice each calendar year at intervals not exceeding 7½ months. PHMSA also proposes revision of § 192.9 to extend § 192.706 leak survey requirements to all Type C gathering pipelines. Further, PHMSA proposes to increase the minimum frequency for performing leakage surveys of gas transmission and Types A and B gathering pipelines located in HCAs in Class 4 locations to four times each calendar year at intervals not exceeding 4½ months.

PHMSA proposes to require each leakage survey on an onshore gas transmission pipeline or Type A, B, or C gathering pipeline to be performed using leak detection equipment and methods that meet the ALDP performance standard in the proposed § 192.763. This proposed change would eliminate the existing automatic, generically available exception at § 192.625 from requirements to use leak detection equipment for gas transmission and Types A and B gathering pipelines in Class 1 and Class 2 locations and odorized pipelines in Class 3 and Class 4 locations. Leakage surveys for onshore gas transmission and Types A, B, and C gathering pipelines would only be performed without the use of leak detection equipment (*i.e.,* solely with the use of human or animal senses) with prior notification and review by PHMSA in accordance with § 192.18, and may only be approved in non-HCA, Class 1, and Class 2 locations. Leakage surveys for offshore gas transmission and offshore gathering pipelines would not require the use of leak detection equipment. PHMSA has not proposed changes to the requirements for leakage surveys for gas transmission and gathering pipelines located outside of HCAs, or for gas transmission and gathering pipelines operating without an odor or odorant.

PHMSA also proposes more frequent leakage surveys for all valves, flanges, tie-ins with valves and flanges, ILI launcher and receiver facilities on gas transmission, offshore gathering, and Types A, B, and C gathering lines. PHMSA similarly proposes more frequent leakage surveys for those gas transmissions, offshore gathering, and Types A, B, and C gathering pipelines known to leak based on material, design, or past operating and maintenance history. Each such facilities identified in this paragraph located in Class 1, Class 2, and Class 3 locations must be surveyed twice each calendar year, and those in Class 4 locations must be surveyed at least four times each calendar year.

§ 192.723 Distribution: Leakage Surveys

PHMSA proposes defining minimum standards for leak survey practices and equipment on gas distribution pipelines through reference to the proposed ALDP performance standard in § 192.763. This proposal would replace the existing requirement at § 192.723 to use leak detection equipment and is described in more detail under the discussion of that section below.

PHMSA also proposes to increase the frequency of leakage surveys on most gas distribution pipelines outside of business districts to once every 3 calendar years, with an interval between surveys not to exceed 39 months. Operators whose procedures or DIMP call for more frequent leakage surveys would be obliged to conduct leakage surveys accordingly. And distribution pipelines outside of business districts at a high risk of leakage would generally be obliged to conduct leakage surveys more frequently: once each calendar year, with the interval between surveys not to exceed 15 months. The following distribution pipelines outside of business districts would be subject to PHMSA's proposed new annual survey requirement:

[295] EPA, ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,'' 87 FR 74702 (Dec. 6, 2022).

1. Cathodically unprotected pipelines on which electrical surveys are impracticable. This would typically cover bare and unprotected distribution lines;

2. Pipelines known to leak based on their material (including, but not limited to, cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history; and

3. Any distribution pipeline protected by a distributed anode system where the cathodic protections survey under § 195.463 showed a deficient reading during the most recent cathodic protection survey.

In determining whether a plastic pipeline is made of a ''historic plastic with known issues'' operators should consider PHMSA and State regulatory actions and industry technical resources identifying systemic integrity issues from plastic pipe that is either comprised of particular materials; or manufactured at particular times, by particular companies, or pursuant to particular processes.

In addition to the above, PHMSA proposes to require, as soon as practicable following ground freezing, heavy rain, flooding, or other environmental conditions that may affect the venting of gas or cause gas migration to nearby buildings, reinvestigation of known leaks (including conducting a leakage survey for possible gas migration). This investigation is to determine whether changes to gas migration or to the facility itself have created a hazard that requires upgrading the leak. Generally, any surface freezing or frost and any flooding near the leak location is likely to affect gas venting and migration through the soil. When determining if heavy rain is likely to affect the venting or migration of leaking gas through the soil, operators should consider the estimated flow rate of the leak, rate of rainfall, local soil conditions, drainage, the presence of other nearby buried structures, and whether the area has a history of flooding.

PHMSA also proposes to require leakage surveys of a distribution pipeline soon (initiated within 72 hours) after the cessation of extreme weather events or land movement that could damage that pipeline segment. PHMSA defines the cessation of the event as either the time that the facility becomes safely accessible to operator personnel, or alternatively the time that the pipeline facility is placed back into service.

§ 192.727 Abandonment or Deactivation of Facilities

PHMSA proposes to revise § 192.727(b) and (c) governing abandonment of gas transmission, distribution, offshore gathering, and Type A gathering pipelines to provide that the existing exception for small gas purge volumes in those paragraphs would be available if purging would not create a risk to public safety specifically.

§ 192.751 Prevention of Accidental Ignition

PHMSA proposes to revise § 192.751(a) governing gas transmission, offshore gathering, and Type A gathering pipelines to clarify that the hazards being addressed in that provision are hazards to public safety specifically. PHMSA also proposes an editorial amendment clarifying that a fire extinguisher must be present, rather than provided, during venting of gas.

§ 192.760 Leak Grading and Repair

PHMSA proposes to create a new § 192.760 addressing requirements for grading and repairing leaks on gas distribution, transmission, offshore gathering, and Types A, B, and C gathering pipelines. The leak grading concept and many of the leak grading criteria are similar to those in the GPTC Guide, which has been adopted in some operator procedures and State pipeline safety requirements.

§ 192.760(a): General

Section 192.760(a) would require operators to have and carry out written procedures for grading and repairing leaks that meet or exceed the minimum requirements of § 192.760. PHMSA's proposed requirements in this paragraph also clarify that § 192.760 would apply to any leak detected by the operator and applies to all components of pipelines (including, but not limited to, pipeline pipe, valves, flanges, meters, regulators, tie-ins, launchers, and receivers). Operators must investigate any leaks discovered immediately and continuously until a leak grade determination has been made.

§ 192.760(b): Grade 1 Leaks

PHMSA proposes to characterize a grade 1 leak as an existing or probable hazard to persons and property or grave hazard to the environment. A grade 1 leak is an urgent or emergency situation and this NPRM proposes to require an operator take immediate and continuous action to eliminate any hazard to public safety and the environment and to promptly complete repair. PHMSA's proposed paragraph (b)(2) includes a list of actions the operator may take to address any hazard pending repair. These steps include activating the operator's emergency plan under § 192.615, evacuating or blocking off the vicinity of the leak, rerouting traffic, eliminating ignition sources, ventilating the leak area to disperse hazardous accumulations of gas, stopping the flow of gas in the facility, or notifying emergency responders. While some of these actions, such as bar holing near the leak, may reduce gas concentration, proposed § 192.760(e) would not allow downgrading a leak to a lower-priority leak grade unless a repair has been made. The operator would have to promptly complete repair even if gas concentration falls to grade 2 or grade 3 levels after the leak location has been vented.

Paragraph (b)(1) provides minimum criteria for grade 1 leaks that would need to be included in operators' leak grading procedures as they demonstrate that a leak poses an existing or probable hazard to public safety or grave hazard to the environment. Operator procedures may supplement those proposed minimum grade 1 criteria as desired. Specific criteria include the following: any leak that operating personnel at the scene determine is an existing or probable hazard to public safety or a grave hazard to the environment; any leak that has ignited; any indication of potential for ignition of accumulated gas resulting from gas migrating into a building, under a building, or into a tunnel; any indication of potential for ignition due to accumulated gas due to migration of gas to the outside wall of a building or to an area from which migration to the outside wall of a building could occur; gas concentration readings approaching LEL within either of a confined space or a substructure from which gas could migrate to the outside of a building; any leak that can be seen, heard, or felt; and any leak that is an incident pursuant to § 191.3.

§ 192.760(c): Grade 2 Leaks

PHMSA proposes to characterize a grade 2 leak as a leak with a probable future hazard to public safety or a significant hazard to the environment. There are currently no explicit Federal pipeline safety requirements to repair such leaks; however, some States and operators have adopted the GPTC Guide, which requires operators to repair such leaks within 12 months of detection. PHMSA proposes to require a grade 2 leak repair be completed within six months in most circumstances, however certain leaks would have shorter repair deadlines.

The proposed minimum criteria for grade 2 leaks reflect gas readings suggesting that a leak has a probable, future hazard to public safety or a significant hazard to the environment, but there is not an existing or probable hazard to public safety or a grave hazard to the environment as a grade 1 leak entails. Operator procedures may supplement those proposed minimum grade 2 criteria as desired. Among PHMSA's proposed minimum criteria are leaks, other than grade 1 leaks, producing a gas reading of 40% LEL or greater under a sidewalk in a wall-to-wall paved area, or a reading of 100% or greater under a street in a wall-to-wall paved area with gas migration that is not a grade 1 leak. Similar to the grade 1 criteria, the grade 2 criteria include criteria based on readings within confined spaces and substructures. A leak reading between 20% LEL and 80% of LEL in a confined space is a grade 2 leak. Unlike the grade 1 criteria, however, the grade 2 criteria make a distinction between gas readings in gas-associated and non-gas associated substructures. A leak must be classified as grade 2 if it produces a reading less than 80% LEL in a non-gas associated substructure from which gas could migrate. A leak with a reading of 80% LEL or greater in a gas associated substructure from which gas could migrate must be classified as a grade 2 leak. Like the grade 1 criteria, this NPRM proposes to require that operators' procedures allow operating personnel at the scene to decide that a leak justifies repair on a grade 2 schedule.

Similar to the discussion of grade 1 leaks, there are differences between the grade 2 criteria proposed in this NPRM and the grade 2 criteria in the GPTC Guide. To ensure timely repair of leaks with relatively large emissions, PHMSA proposes to require that any leak other than a grade 1 leak with a leakage rate of 10 CFH) or more be classified as a grade 2 leak. Additionally, in the NPRM, grade 2 is the minimum grade for any leak on a gas transmission pipeline or Type A or C gathering pipeline, or any leak of LPG or hydrogen that does not qualify as grade 1 leak.

PHMSA proposes to require that operators repair grade 2 leaks within 6 months of detection, or any alternative timeline identified in an operator's procedures or IM plan, whichever is earlier. Operators must reevaluate each grade 2 leak once every 30 days until the leak repair is completed or the leak is cleared (or, if a grade 2 leak must be repaired within 30 days, every 2 weeks until the repair has been completed). However, PHMSA proposes to require operators to prioritize repair of some grade 2 leaks based on their higher potential for public safety and environmental consequences. For example, PHMSA proposes to require any leak on a gas transmission or Type A gathering pipeline, each in an HCA or a Class 3 or Class 4 location (and that is not a grade 1 leak) to be repaired within 30 days of detection, or the operator must take continuous action to monitor and repair the leak. Additionally, PHMSA proposes to require each operator's leak grading and repair procedures to include a methodology for prioritizing grade 2 leak repairs, including criteria for leaks that must be repaired within 30 days or less. The operator's methodology must include an analysis of the volume and migration of gas emissions, the proximity of gas to buildings and subsurface structures, the extent of pavement, and soil type and conditions that affect the possibility for gas migration such as frost conditions or soil moisture. This NPRM also proposes to require an operator complete repair of an existing grade 2 leak or take other immediate and continuous action to complete repairs and eliminate hazards when changing environmental conditions that may affect the venting or migration of gas that could allow gas to migrate to the outside wall of a building. Environmental changes that could contribute to gas migration include ground freezing, heavy rains or flooding, or the installation of new pavement.

Finally, PHMSA proposes to require that operators complete repairs of grade 2 leaks known to exist on or before the effective date of the rule within 1 year from the date of publication of the final rule.

§ 192.760(d): Grade 3 Leaks

PHMSA proposes to characterize a grade 3 leak as any leak that does not meet its minimum proposed grade 1 or grade 2 criteria. Like grade 2 leaks, there is no current Federal standard requiring repair of such leaks, and the GPTC Guide does not require a minimum repair schedule. Illustrative examples of grade 3 leaks as contemplated by this NPRM include (but are not limited to) leaks with a reading of less than 80% LEL in gas-associated substructures from which gas is unlikely to migrate, any reading of gas under pavement outside of wall-to-wall paved areas where it is unlikely that gas could migrate to the outside wall of a building, or a reading of less than 20% LEL in a confined space.

PHMSA proposes to require an operator to complete repair of each grade 3 leak within 24 months of the date the leak was detected and require each grade 3 leak be re-evaluated once every six months until the leak repair has been completed. However, PHMSA proposes to allow an operator to continue to monitor a grade 3 leak provided the pipeline segment containing the leak is scheduled for replacement and is in fact replaced, within five years of the date the leak was detected. Finally, PHMSA proposes to require a grade 3 leak known to exist on or before the effective date of the rule be repaired within 3 years from the date of publication of the final rule, unless the pipeline is scheduled for replacement within five years from the effective date of the rule.

§ 192.760(e): Post-Repair Inspection

PHMSA in proposed § 192.760(e) defines requirements for determining and documenting that a complete and effective repair of a leak has been accomplished. PHMSA proposes to require that, in order for a leak repair to be complete, an operator must perform a permanent repair and obtain, during a post-repair inspection, a gas concentration reading of 0% gas at the leak location. A temporary repair may be used to downgrade a leak in accordance with proposed § 192.760(g). Proposed § 192.760(e)(2) would require that the first post-repair inspection be completed no sooner than 14 days but no later than 30 days after the date of repair.

Proposed § 192.760(e)(3) provides for enhanced repair and monitoring requirements if a post-repair inspection yields a gas reading greater than 0% gas. Specifically, if a post-repair inspection indicates that a grade 1 or 2 condition exists, the operator would need to reevaluate the repair and take immediate and continuous action to eliminate the hazard and complete the repair. If a grade 1 or grade 2 condition did not exist, the operator would need both to re-inspect the leak every 30 days and complete the repair within either of the repair deadline for a grade 3 leak under § 192.760(d)(2) or (for a leak that was downgraded after the initial repair) a new repair deadline established under § 192.760(g). Lastly, proposed § 192.760(e)(4) would provide that post-repair inspection would not be necessary if leak remediation was completed via routine maintenance activities such as cleaning, lubrication, or adjustment.

§ 192.760(f) and (g): Upgrading and Downgrading

Proposed § 192.760(f) and (g) describe the repair deadlines and requirements for leaks that are upgraded or downgraded to higher or lower -priority grades. Operators who receive information that a higher-priority grade condition exists on a previously graded leak would need to upgrade that leak to a higher-priority grade. For a leak that is upgraded, PHMSA proposes to require that the deadline for the repair would be the earlier of either the remaining time based on the original leak grade, or the time allowed for repair for the upgraded leak measured from the time the operator receives information that a higher-priority grade condition exists. In other words, an operator would not be permitted to extend the repair deadline by upgrading a leak.

PHMSA also proposes to prohibit downgrading of a leak unless a temporary repair has been made or a permanent repair to the pipeline has been attempted but gas was detected during the post-repair inspection required by proposed § 192.760(e). For example, a leak may not be downgraded simply by venting the leak location until gas measurements fall to grade 3 levels, with no action taken to permanently remediate the leak. A leak may be downgraded if the facility was the subject of an attempt at permanent repair, but a non-zero reading was measured during the post-repair inspection described in the discussion of § 192.760(e). If a leak were downgraded after the attempted permanent repair, the time period for completion of repair would be the remaining time allowed for repair under its new grade, measured from the time the leak was initially detected.

§ 192.760(h) Extension of Leak Repair

PHMSA proposes to allow an extension of the repair deadline requirements for individual grade 3 leaks only on a case-by-case basis. This extension requires notification to, and review by, PHMSA pursuant to the procedures in § 192.18. An operator may request an extension if the delayed repair timeline would not result in increased risks to public safety, and the operator can demonstrate either that the prescribed repair schedule is impracticable, an alternative repair schedule is necessary for safety, or remediation within the specified time frame would result in the release of more gas to the environment than would otherwise occur if the leak were allowed to continue. For example, if the repair of a grade 3 leak would require significant emissions to blowdown the facility, delaying repair to coordinate with other maintenance requiring shutdown (and thereby minimizing the total number of blowdowns) may be appropriate. PHMSA proposes to require that a notification under this paragraph include descriptions of the leak, the leaking facility, the leak environment, the proposed extended repair schedule, the justification for an extended repair schedule and proposed emissions mitigation methods.

§ 192.760(i): Recordkeeping

Proposed § 192.760(i) describes recordkeeping requirements associated with leak grading and repair. Beginning on the effective date of the rule, PHMSA proposes that records documenting the complete history of investigation and grading of each leak prior to completion of the repair would need to be retained until five years after the date of the final post-repair inspection performed under proposed paragraph § 192.760(e). These records include documentation of grading monitoring, inspections, upgrades, and downgrades. PHMSA also proposes that records associated with the detection, remediation, and repair of each leak must be maintained for the life of the pipeline. Permanent recordkeeping would apply to both piping and non-piping portions of the pipeline. Complete records of the location and timing of leaks and repairs is necessary for an adequate leak management program.

§ 192.763 Advanced Leak Detection Program

PHMSA proposes to create § 192.763 that would require operators of gas distribution, transmission, offshore gathering, and Types A, B, and C gathering pipelines establish a written Advanced Leak Detection Program (ALDP) and establish performance standards for both the sensitivity of leak detection equipment and for the effectiveness of operators' ALDPs. The ALDP represents a comprehensive set of technologies and procedures that an operator would use to detect all leaks consistent with the proposed ALDP performance standard at § 192.763(b). PHMSA proposes to require that an operator's written ALDP include four main elements: leak detection equipment, leak detection procedures, prescribed leakage survey frequencies, and program evaluation.

The first element in an ALDP is the leak detection equipment that operators would use to perform leakage surveys, pinpoint leak locations, and investigate leaks. These equipment requirements are proposed in § 192.763(a)(1). Operator ALDPs would include a list of leak detection technologies that the operator would use for leakage surveys, pinpointing leak location, and leak investigations. Leak detection equipment is not required for surveys of offshore gas transmission and offshore gathering pipelines because offshore leaks are visibly conspicuous. PHMSA further proposes that any leak detection equipment must have a minimum sensitivity of 5 ppm (§ 192.763(a)(1)(ii)) to ensure detection of leaks consistent with the proposed ALDP performance standard at § 192.763(b). An operator may need to use more sensitive equipment than required by § 192.763(a)(1)(ii)—or supplemental equipment or techniques (*e.g.,* soap bubble testing)—to meet that ALDP performance standard depending on the leak detection procedures used and the operating characteristics and environment of the pipeline. Alternatively, operators of each of (1) natural gas transmission and part 192-regulated gathering pipelines, each of which are located either offshore or in Class 1 or 2 locations, and (2) any gas pipeline transporting flammable, toxic, or corrosive gas other than natural gas, may (pursuant to § 192.763(c)) request use of alternative leak detection equipment by submitting a § 192.18 notification for PHMSA review.

PHMSA proposes to require operators select leak detection equipment within their ALDPs based on a documented analysis that reflects the state of commercially available advanced leak detection technologies and practices, and considers at a minimum the size, configuration, operating parameters, and operating environment of the operator's system (§ 192.763(a)(1)(iii)). PHMSA further proposes an operator's analysis consider the appropriateness of specified examples of possible advanced leak detection technologies, including each of the following: handheld equipment, including optical, infrared, or laser-based devices; continuous monitoring via stationary gas detectors, pressure monitoring or other means; mobile surveys from vehicle or aerial platforms; or systemic use of any other commercially available advanced technology capable of meeting the program performance standard in § 192.763(b).

The second program element in proposed § 192.763(a)(2) consists of the operator's written procedures related to leak detection. PHMSA proposes that, at a minimum, the ALDP must include procedures for performing compliant leakage surveys for each of the leak detection equipment included in an operator's ALDP. To ensure that operators use procedures appropriate for environmental conditions such as temperature, wind, time of day, precipitation and humidity, the operator must define under which conditions the procedure may and may not be used. Additionally, those procedures must be consistent with any instructions of the leak detection equipment manufacturer regarding environmental and operational conditions parameters for use.

PHMSA proposes to require that an operator's procedures must provide for pinpointing the location of all leak indications with the use of handheld leak detection equipment (§ 192.763(a)(2)(ii)). As described above, any equipment used for pinpointing leaks must generally (for onshore gas transmission, Types A, B, and C gathering, and distribution pipelines) have a minimum sensitivity of 5 ppm or less. If a leak location was pinpointed with handheld leak detection equipment meeting this standard during the initial survey, PHMSA would not expect an operator to re-survey the area to meet the requirement of this paragraph.

To ensure the quality of leak detection equipment, PHMSA also proposes at § 192.763(a)(2)(iii) to require that an operator have procedures for validating that a leak detection device used in its ALDP meets the 5-ppm sensitivity requirement in § 192.763(a)(1)(ii) prior to initial use. This consists of testing the equipment measurements against a known concentration of gas. The operator must maintain records that the leak detection equipment has been validated for five years after the date that the device ceases to be used in the operator's ALDP. Separate from the one-time validation requirement, PHMSA also proposes to require that operators have procedures for the maintenance and calibration of leak detection equipment (§ 192.763(a)(2)(iv)). At a minimum the operator must follow the maintenance and calibration procedures recommended by the equipment manufacturer. PHMSA further proposes to require that an operator recalibrate leak detection equipment following an indication of malfunction.

The third required element of an ALDP in proposed § 192.763(a)(3) is the frequency of leakage surveys. As discussed above, PHMSA proposes to define minimum leakage survey frequencies in § 192.723 for gas distribution pipelines and in § 192.706 for gas transmission, offshore gathering, and Types A, B, and C gathering pipelines. However, PHMSA also proposes that if more frequent leakage surveys are necessary to meet the ALDP performance standard in proposed § 192.763(b) or otherwise specified by the operator, those frequencies must be noted in the operator's ALDP. More frequent leakage surveys may be required for less sensitive leak detection equipment, challenging survey conditions, or facilities with a high leakage frequency.

The final element of an ALDP consists of proposed requirements in § 192.763(a)(4) for operator procedures governing program evaluation and improvement. At least annually, operators must re-evaluate the elements of their ALDP considering, at a minimum, each of the following: the performance of leak detection equipment used, advances in leak detection technologies and practices, the number of leaks initially detected by third parties, the number of leaks and incidents overall, and estimated emissions from leaks. This is similar in principle to the existing continuous improvement requirements under IM requirements in part 192, subparts O and P, as well as requirements for certain operators to periodically review procedures under § 192.605(b)(8) and (c)(4). If an operator finds evidence that their ALDP fails to detect leaks during leakage surveys as required by the ALDP performance standard at § 192.763(b), it must make changes to program elements to ensure that the minimum performance standard in § 192.763(b) is met. Operators must consider ways to improve their leak detection programs based on leak detection performance data and advances in technology.

PHMSA's proposed ALDP performance standard at § 192.763(b) includes a holistic, program-wide performance standard for the ALDP elements listed in § 192.763(a). PHMSA proposes to require that an ALDP for gas transmission, distribution, offshore gathering, and Types A, B, and C gathering pipelines must be capable of detecting all leaks that produce a reading of 5 ppm of gas or greater when measured from a distance of 5 feet from the pipeline, or from within a wall-to-wall paved area. The performance standard of detecting leaks of a size large enough to produce a reading of 5 ppm is a measurement of minimum detectible leak size rather than the sensitivity of equipment itself. PHMSA further proposes that each ALDP must be validated and documented with engineering tests and analyses, and that such records should be maintained for five years after the date that ALDP is no longer used by the operator.

Lastly, PHMSA proposes at § 192.763(c) the ability for certain operators (specifically, each of (1) natural gas transmission, offshore gathering, and Types A, B, and C gathering pipelines located in Class 1 or 2 locations and (2) any gas pipeline transporting flammable, toxic, or corrosive gas other than natural gas) to request use of an alternative performance standard, pursuant to the notification and PHMSA review procedures established in § 192.18. PHMSA proposes to require that any notifications submitted under this provision must include, among other things, information about the location, design, gas being transported, operational parameters, environmental conditions, and material properties and history of the pipeline, the proposed alternative performance standard, and a description of any leak detection equipment and procedures that would be used.

§ 192.769 Qualification of Leakage Survey, Investigation, and Grading Personnel

PHMSA proposes to clarify at § 192.769 training and qualification requirements for personnel that conduct leakage surveys, investigation, and leak grading on gas transmission, distribution, offshore gathering, and Types A gathering pipelines. Section 192.769 proposes to require that all such personnel must be qualified under subpart N and have documented work history or training in conducting leakage surveys, investigation, and grading. This requirement clarifies that surveying, investigating, grading, and repairing leaks are covered tasks under subpart N.

§ 192.770 Minimizing Emissions From Gas Transmission Pipeline Blowdowns

PHMSA in a new § 192.770 proposes to require gas transmission, offshore gathering, and Type A gathering pipeline operators minimize the release of gas to the environment from intentional, vented emissions (including for repairs, construction, operations, or maintenance). PHMSA does not, however, propose to require mitigation for emergency releases (*e.g.,* emergency blowdowns) associated with the activation of an operator's emergency plan under § 192.615(a)(3). However, an operator must document when an emergency release occurs, and the justification for not taking mitigative action.

The proposed regulatory text provides examples of approved mitigation methods from which pertinent operators may choose to prevent or mitigate vented emissions. The first method is installing and using valves or control fittings to reduce the volume of gas that must be removed from the pipeline. The second method listed is routing vented gas to a flare stack to be ignited or to other equipment for consumption. The third, fourth, and fifth methods each involve reducing the pressure of a pipeline segment prior to venting, reducing total emissions volume. In the third example, an operator isolates the pipeline segment upstream of the venting segment and uses the downstream compressor station to reduce the pressure of the affected segment. The fourth example is similar except instead of the compressor station, an operator uses a mobile compressor unit to reduce the pressure of the venting segment by compressing gas into adjacent facilities or a storage vessel. The fifth example is like the fourth, except it may be performed without compression. PHMSA also proposes that operators may request, pursuant to the notification procedure at § 192.18, use of alternative approaches for mitigating vented emissions not listed in the proposed regulatory text, but which would provide reduce emissions by at least 50% compared with venting gas to the atmosphere without mitigative action.

Lastly, PHMSA proposes that operators document the methodology used in their procedures, including by documenting an analysis on how its selected method minimizes the release of natural gas to the environment.

§ 192.773 Pressure Relief Device Maintenance and Adjustment of Configuration

PHMSA in a new § 192.773 proposes to require operators of all gas distribution, transmission, offshore gathering, and Types A, B, and C gathering pipelines to have written operating and maintenance procedures for assessment of the proper function of pressure relief devices. PHMSA's proposed regulatory text would require operators to assess and either repair or replace malfunctioning pressure relief devices. PHMSA's proposed language also identifies specific action operators would have to take on operation of a malfunctioning pressure relief device, to include immediate repair or replacement of relief devices that fail to provide adequate overpressure protection. If a relief device activates and releases gas below the set pressure ranges defined in the operator's operations and maintenance manual, the operator must take immediate and continuous action to stop further releases of gas and ensure adequate overpressure protection. In the latter case, the device must be repaired or replaced as soon as practicable but within 30 days of actuation. PHMSA further notes that operators would be obliged to maintain records documenting the proper operation and any remediation/replacement of pressure relief devices for the service life of their facilities.

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

PHMSA proposes to revise § 192.1007(e)(1)(i) and (v) to delete existing references to § 192.703(c) that would be rendered inapposite by PHMSA's proposed adoption of a different meaning for ''hazardous leak'' applicable to § 192.703(c) than would be applicable within its integrity management regulations at subparts O and P.

§ 193.2503 Operating Procedures

Section 193.2503(c) obliges operators of part 193-regulated LNG facilities to have and follow written procedures for normal and abnormal operations. PHMSA proposes to revise the regulatory language in this provision to incorporate within its regulations the section 114 of the PIPES Act of 2020 self-executing mandate that operators update their procedures to provide for the elimination of leaks and minimize release of gas from pipeline facilities.

§ 193.2523 Minimizing Emissions From Blowdowns and Boiloff

PHMSA proposes to add a new § 193.2523 to require operators of part 193-regulated LNG facilities to mitigate methane emissions from non-emergency, vented releases such as blowdowns and tank boiloff. PHMSA's proposed mitigation and documentation requirements in § 193.2523 largely mirror those described in the section V discussion of proposed § 192.770.

§ 193.2605 Maintenance Procedures

Section 193.2605(b) obliges operators of part 193-regulated LNG facilities to have and follow written maintenance procedures. PHMSA proposes to revise the regulatory language in this provision to incorporate within its regulations the section 114 of the PIPES Act of 2020 self-executing mandate that operators update their procedures to provide for the elimination of leaks and minimize release of gas from pipeline facilities.

§ 193.2624 Leakage Surveys

PHMSA proposes to create a new section requiring operators of LNG facilities to perform periodic methane leakage surveys on methane or LNG-containing components and equipment at least four times each calendar year, with a maximum interval between surveys not to exceed 4½ months. This requirement would apply to part 193-regulated LNG facilities. The methane leakage surveys would need to be performed with leak detection equipment satisfying the 5-ppm minimum sensitivity standard proposed for part 192-regulated gas pipelines elsewhere in this NPRM. Methane leaks and other conditions discovered during the surveys would need to be remediated in accordance with the operators' maintenance or abnormal operating conditions procedures, to include any repair schedules within those procedures. Leakage survey records, including records of equipment validation and calibration, must be maintained for 5 years after the leakage survey is completed.

VI. Regulatory Analysis and Notices

A. Legal Authority for This Rulemaking

This proposed rule is published under the authority of the Secretary of Transportation delegated to the PHMSA Administrator pursuant to 49 CFR 1.97. Among the statutory authorities delegated to PHMSA are those set forth in the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*) (authorizing, inter alia, issuance of regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities) and section 28 of the Mineral Leasing Act, as amended (30 U.S.C. 185(w)(3)). For a complete listing of authorities, *see* 49 CFR 1.97.

This NPRM proposes to implement several provisions of the PIPES Act of 2020, including sections 113 (codified at 49 U.S.C. 60102(q)), 114 (codified at 49 U.S.C. 60108(a)), and 118 (codified at 49 U.S.C. 60102(b)(5)). While section 113 of the PIPES Act of 2020 does not mandate that PHMSA issue leak detection and repair program requirements for Type C gas gathering pipelines in Class 1 locations, 49 U.S.C. 60101(b) and 60102 grant authorities to issue standards for the transportation of gas via any part 192-regulated gathering pipelines to protect public safety and the environment, which include Type C gas gathering pipelines. As explained in section II.E of this NPRM, fugitive emissions from all gas gathering pipelines (including Type C gas gathering pipelines in Class 1 locations) are a significant source of methane emissions which directly harm the environment by contributing to climate change—which (as explained in section II.B of this NPRM) itself entails public safety and environmental risks. Further, as explained in section II.D.3 of this NPRM and discussed in further detail in the Preliminary RIA, releases of natural gas (particularly unprocessed natural gas from Type C and other gas gathering pipelines) contain HAPs and VOCs are particularly harmful to public safety and the environment.

Further, 49 U.S.C. 60117(c) authorizes PHMSA to require owners and operators of gas gathering, transmission, and distribution pipelines and other pipeline facilities to submit information (including, as appropriate, each of annual reports, incident reports, and intentional release reports, and NPMS information as proposed in this NPRM) required for regulation of those pipeline facilities under the Federal Pipeline Safety Statutes. Further, section 60117(c) authorizes the Secretary to require owners and operators of Type R gas gathering pipelines to submit the same information to support future decision making regarding whether and to what extent to impose requirements in 49 CFR part 192 on those gas gathering pipelines.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

E.O. 12866 (''Regulatory Planning and Review''),[296] as amended by E.O. 14094 (''Modernizing Regulatory Review''),[297] requires that agencies ''should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating.'' Agencies should consider quantifiable measures and qualitative measures of costs and benefits that are difficult to quantify. Further, E.O. 12866 requires that ''agencies should select those [regulatory] approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach.'' Similarly, DOT Order 2100.6A (''Rulemaking and Guidance Procedures'') requires that regulations issued by PHMSA and other DOT Operating Administrations should consider an assessment of the potential benefits, costs, and other important impacts of the proposed action and should quantify (to the extent practicable) the benefits, costs, and any significant distributional impacts, including any environmental impacts.

E.O. 12866, as amended, and DOT Order 2100.6A require that PHMSA submit ''significant regulatory actions'' to the Office of Management and Budget (OMB) for review. This action has been determined to be significant under E.O. 12866, as amended. It is also considered significant under DOT Order 2100.6A because of significant congressional, State, industry, and public interest in pipeline safety. The proposed rule has been reviewed by OMB in accordance with E.O. 12866 and is consistent with the requirements of E.O. 12866, as amended, and DOT Order 2100.6A.

E.O. 12866, as amended, and DOT Order 2100.6A also require PHMSA to provide a meaningful opportunity for public participation, which reinforces requirements for notice and comment in the Administrative Procedure Act (APA, 5 U.S.C. 551 *et seq.*). In accord with the requirement, PHMSA seeks public comment on the proposals in the NPRM (including preliminary cost and cost savings analyses pertaining to those proposals set forth in the preliminary RIA, as well as discussions of the public safety, environmental, and equity benefits in that document and the draft Environmental Assessment), as well as any information that could assist in evaluating the benefits and costs of this NPRM.[298]

The quantified benefits of the final rule consist of the climate benefits of avoided methane emissions and the market value of avoided natural gas losses. PHMSA expects additional, unquantified benefits including safety benefits from early detection of leaks before they can evolve into incidents and detection of integrity threats on gas transmission and gathering pipelines from right-of-way patrols. PHMSA also expects additional unquantified environmental and public health benefits associated with preventing releases of natural gas, and other flammable, toxic or corrosive gases, and expects these benefits to be important given the types of health effects resulting from exposure to air pollutants (*e.g.,* asthma and other respiratory effects, cancer). PHMSA invites commenters to provide additional information that would enable quantification of the additional health and safety benefits of the rule.

The table below summarizes the annualized quantified costs and benefits for the provisions in the final rule at a 3 percent and a 7 percent discount rate (discussed in further detail in the Preliminary RIA for this NPRM, available in the rulemaking docket):

ANNUALIZED MONETIZED COSTS AND BENEFITS

[Million 2020$]

Discount rate (%)	Item	Gathering	Transmission	Distribution		Total [1]	
				Lamb *et al.* (2015)	Weller *et al.* (2020)	Low	High
3	Benefits	$553	$12	$515	$1,754	$1,081	$2,320
	Costs	211	15	514	654	740	880
	Net benefits	343	−3	1	1,100	341	1,440
7% [2]	Benefits	549	12	512	1,743	1,073	2,304
	Costs	209	15	530	677	753	900
	Net benefits	340	−3	−18	1,067	320	1,404

[1] Total costs and benefits are presented as a range to reflect different assumptions regarding leak incidence and methane emissions rate across pipe materials. The low estimate reflects distribution costs based on Lamb *et al.* (2015) whereas the high estimate reflects distribution costs based on Weller *et al.* (2020).

[2] Costs and benefits of natural gas losses are discounted at 7 percent, whereas climate benefits are based on the average SC–CH_4 at 3 percent discount. See section 5 of the Preliminary RIA for estimated climate benefits using other discount rates.

Source: PHMSA analysis.

Benefits of the final rule would depend on, among other things, the degree to which compliance actions result in additional safety and gas release avoidance and mitigation measures, relative to the baseline, and

[296] 58 FR 51735 (Oct. 4, 1993).

[297] 88 FR 21879 (April 11, 2023).

[298] PHMSA also participated in OMB-led E.O. 12866 meetings requested by public stakeholders during interagency regulatory review of this NPRM, including EDF (March 9, 2023), PST (March 17, 2023), and Boundary Stone Partners/Aclima, Inc. (March 20, 2023). Summaries of each E.O. 12866 meeting are available in the rulemaking docket at Doc. No. PHMSA–2021–0039.

the effectiveness of these measures in preventing or mitigating future releases or incidents from gas pipeline facilities subject to this NPRM.

C. Executive Order 13132: Federalism

PHMSA analyzed this NPRM in accordance with the principles and criteria contained in E.O. 13132 (''Federalism'')[299] and the Presidential Memorandum (''Preemption'') published in the **Federal Register** on May 22, 2009.[300] E.O. 13132 requires agencies to assure meaningful and timely input by State and local officials in the development of regulatory policies that may have ''substantial direct effects on the States, on the relationship between the National Government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This NPRM is not expected to have a substantial direct effect on State and local governments, the relationship between the National Government and the States, or the distribution of power and responsibilities among the various levels of government. This NPRM is not expected to impose substantial direct compliance costs on State and local governments.

While the NPRM may operate to preempt some State requirements, it would not impose any regulation that has substantial direct effects on the States, the relationship between the National Government and the States, or the distribution of power and responsibilities among the various levels of government. Section 60104(c) of Federal Pipeline Safety Laws prohibits certain State safety regulation of interstate pipelines. Under Federal Pipeline Safety Laws, States that have submitted a current certification under section 60105(a) can augment Federal pipeline safety requirements for intrastate pipelines regulated by PHMSA but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility that PHMSA does not regulate. In this instance, the preemptive effect of the regulatory amendments in this NPRM would be limited to the minimum level necessary to achieve the objectives of the Federal Pipeline Safety Laws. Therefore, the consultation and funding requirements of E.O. 13132 do not apply.

[299] 64 FR 43255 (Aug. 10, 1999).

[300] 74 FR 24693 (May 22, 2009).

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires Federal agencies to conduct an initial Regulatory Flexibility Analysis (IRFA) for a proposed rule subject to notice-and-comment rulemaking under the APA unless the agency head certifies that the proposed rule will not have a significant economic impact on a substantial number of small entities. E.O. 13272 (''Proper Consideration of Small Entities in Agency Rulemaking'')[301] obliges agencies to establish procedures promoting compliance with the Regulatory Flexibility Act. The DOT posts its implementing guidance on a dedicated web page.[302] This NPRM was developed in accordance with E.O. 13272 and DOT guidance to promote compliance with the Regulatory Flexibility Act and to ensure that the potential impacts of the rulemaking on small entities has been properly considered.

PHMSA conducted an IRFA, which has been made available in the docket within the Preliminary RIA for this rulemaking. PHMSA has preliminarily determined that the proposed rule could result in a significant economic impact on a substantial number of small entities, depending on the degree to which operators are able to pass-through costs. PHMSA seeks comment on whether the proposed rule, if adopted, would have a significant economic impact on a significant number of small entities.

E. National Environmental Policy Act

The National Environmental Policy Act (NEPA, 42 U.S.C. 4321 *et. seq.*) requires Federal agencies to consider the consequences of major Federal actions and prepare a detailed statement on actions significantly affecting the quality of the human environment. The Council on Environmental Quality implementing regulations (40 CFR parts 1500–1508) require Federal agencies to conduct an environmental review considering (1) the need for the action, (2) alternatives to the action, (3) probable environmental impacts of the action and alternatives, and (4) the agencies and persons consulted during the consideration process. DOT Order 5610.1C (''Procedures for Considering Environmental Impacts'') establishes departmental procedures for evaluation of environmental impacts under NEPA and its implementing regulations.

[301] 67 FR 53461 (Aug. 16, 2002).

[302] DOT, ''Rulemaking Requirements Related to Small Entities,'' *https://www.transportation.gov/regulations/rulemaking-requirements-concerning-small-entities* (last accessed June 17, 2021).

PHMSA analyzed this NPRM in accordance with NEPA, NEPA implementing regulations, and DOT Order 5610.1C. PHMSA has prepared a draft environmental assessment (DEA) and preliminarily determined this action will not significantly affect the quality of the human environment. To the extent that the NPRM has impacts on the environment, these are primarily beneficial ecological and human health impacts from early detection of gas leaks and minimizing emissions of methane, a powerful GHG that contributes to climate change. A copy of the draft EA for this action is available in the docket. PHMSA invites comment on the environmental impacts of this NPRM.

F. Environmental Justice

E.O. 12898 (''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations''),[303] as supplemented by the E.O. entitled ''Revitalizing Our Nation's Commitment to Environmental Justice for All'' (April 21, 2023),[304] directs Federal agencies to take appropriate and necessary steps to identify and address disproportionately high and adverse effects of Federal actions on the health or environment of minority and low-income populations ''[t]o the greatest extent practicable and permitted by law.'' DOT Order 5610.2C (''U.S. Department of Transportation Actions to Address Environmental Justice in Minority Populations and Low-Income Populations'') establishes departmental procedures for effectuating E.O. 12898 promoting the principles of environmental justice through full consideration of environmental justice principles throughout planning and decision-making processes in the development of programs, policies, and activities, including PHMSA rulemaking.

PHMSA has evaluated this NPRM under DOT Order 5610.2C and E.O. 12898 and has preliminarily determined it will not cause disproportionately high and adverse human health and environmental effects on minority and low-income populations. The NPRM is facially neutral and national in scope; it is neither directed toward a particular population, region, or community, nor

[303] 59 FR 7629 (Feb. 16, 1994).

[304] E.O. number and **Federal Register** citation forthcoming. *See* White House, ''Executive Order on Revitalizing Our Nation's Commitment to Environmental Justice for All'' (April 21, 2023), *https://www.whitehouse.gov/briefing-room/presidential-actions/2023/04/21/executive-order-on-revitalizing-our-nations-commitment-to-environmental-justice-for-all/#:~:text=We%20must%20advance%20environmental%20justice,human%20health%20and%20the%20environment.*

is it expected to adversely impact any particular population, region, or community. And insofar as PHMSA expects the rulemaking would reduce the safety and environmental risks associated with gas gathering, transmission, and distribution lines, many of which are located in the vicinity of environmental justice communities,[305] PHMSA does not expect the regulatory amendments introduced by this final rule would entail disproportionately high adverse risks for minority or low-income populations in the vicinity of those pipelines. Lastly, as explained in the draft environmental assessment, PHMSA expects that its proposed regulatory amendments will yield GHG emissions reductions, thereby reducing the risks posed by anthropogenic climate change to minority and low-income populations.

G. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

PHMSA analyzed this NPRM according to the principles and criteria in E.O. 13175 (''Consultation and Coordination with Indian Tribal Governments'')[306] and DOT Order 5301.1 (''Department of Transportation Programs, Polices, and Procedures Affecting American Indians, Alaska Natives, and Tribes''). E.O. 13175 requires agencies to assure meaningful and timely input from Tribal government representatives in the development of rules that significantly or uniquely affect Tribal communities by imposing ''substantial direct compliance costs'' or ''substantial direct effects'' on such communities or the relationship and distribution of power between the Federal Government and Tribes.

PHMSA assessed the impact of the NPRM and has preliminarily determined that it will not significantly or uniquely affect Tribal communities or Indian Tribal governments. The rulemaking's regulatory amendments are facially neutral and would have broad, national scope; PHMSA, therefore, does not expect this NPRM to significantly or uniquely affect Tribal communities, much less impose substantial compliance costs on Native American Tribal governments or mandate Tribal action. Insofar as PHMSA expects the rulemaking will improve safety and reduce public safety and environmental risks associated with gas pipelines, PHMSA believes it will not entail disproportionately high adverse risks for Tribal communities. While PHMSA is not aware of specific Tribal-owned business entities that operate part 192-regulated gas pipelines, any such business entities could be subject to direct compliance costs as a result of this proposed rule. Because PHMSA does not anticipate that this proposed rule would have tribal implications, the funding and consultation requirements of E.O. 13175 would not apply. PHMSA seeks comment on the applicability of E.O. 13175 to this proposed rule and the existence of any Tribal-owned business entities operating pipelines affected by the proposed rule (along with the extent of such potential impacts).

H. Executive Order 13211

E.O. 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'')[307] requires Federal agencies to prepare a Statement of Energy Effects for any ''significant energy action.'' E.O. 13211 defines a ''significant energy action'' is defined as any action by an agency (normally published in the **Federal Register**) that promulgates, or is expected to lead to the promulgation of, a final rule or regulation (including a notice of inquiry, ANPRM, and NPRM) that (1)(i) is a significant regulatory action under E.O. 12866 or any successor order and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

This NPRM is a significant action under E.O. 12866, as amended; however, it is not likely to have a significant adverse effect on supply, distribution, or energy use, as further discussed in the Preliminary RIA. Further, OIRA has not designated this NPRM as a significant energy action.

I. Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. The proposals in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM would trigger new reporting and notification requirements for operators of natural gas transmission, distribution, and gathering pipelines. PHMSA proposes new and revised reporting requirements intended to improve the quality of the data available concerning pipeline leaks and other sources of emissions.

Reporting Releases of Gas

PHMSA proposes to require pipeline operators to submit data on intentional and unintentional releases of gas with a volume of 1 MMCF or greater excluding certain events that had been reported as incidents under §§ 191.9 or 191.15. To collect this data, PHMSA proposes the creation of a new large-volume emissions report to parallel existing incident reporting requirements. Operators would be required to submit this data upon each occurrence of a release that meets the reporting requirement within 30 days from the date of detection or 30 days from the date that a previously detected release became reportable. These new large-volume gas release reports would provide valuable information on the primary sources and causes of vented emissions and the causes of large-volume leaks that do not qualify as incidents. This data would address information gaps in the current incident reporting requirements with respect to intentional releases and environmentally hazardous unintentional releases with release volumes between 1 MMCF and 3 MMCF. PHMSA estimates that it would receive 373 reports on average each year (239 and 134 reports for gathering and transmission, respectively), with each report estimated to require 4 hours to prepare.

Annual Report Revisions

PHMSA also proposes revisions to the existing gas transmission, gathering, and distribution annual report forms to include reporting of leaks discovered and repaired by grade, estimated leak emissions by grade, and estimated annual emissions from other sources by source category. Currently, these forms include data on leak repair, however they lack data on leaks discovered and data on emissions generally.

Safety-Related Condition Reporting

PHMSA proposes an exception from § 191.23 safety-related condition reporting requirements for events that are reported as large-volume gas releases. The proposed exception for large-volume incident reports would be consistent with the existing exception at § 191.23(b) for events reported as incidents. Because large-volume gas release reports would have roughly equivalent detail to an incident report,

[305] *See* Ryan Emmanuel, et al., ''Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States,'' 5:6 GeoHealth (June 2021), *https://agupubs.onlinelibrary.wiley.com/toc/24711403/2021/5/6* (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).

[306] 65 FR 67249 (Nov. 9, 2000).

[307] 66 FR 28355 (May 22, 2001).

a less detailed safety-related condition report would not be necessary. PHMSA expects the burden for this information collection to decrease because of this change.

National Pipeline Mapping System Reporting

This NPRM proposes to extend the reporting requirements at § 191.29 for the NPMS to offshore gathering pipelines as well as Types A, B, and C regulated onshore gas gathering pipelines. Currently only gas transmission pipelines are required to provide geospatial data on their pipeline systems in accordance with the NPMS requirements at 49 U.S.C. 60132 and 49 CFR 191.29. The collection of geospatial data from gas gathering pipelines would provide PHMSA critical knowledge about the location and operating characteristics of these pipelines to assist in the identification and remediation of leaks.

Notification Requirements

PHMSA requires operators to make notifications in accordance with § 192.18 90 days in advance of using an alternative technology or assessment method. Operators may proceed only if they do not receive a letter objecting to the proposed use of other technology and/or methods.

PHMSA proposes, in § 192.706(a), to allow operators to request the use of human senses, in lieu of leak detection equipment, when conducting a leak survey if the operator provides advance notification to PHMSA in accordance with § 192.18.

In § 192.763(c), PHMSA proposes to allow operators to request to use an alternative advanced leak detection performance standard if the operator notifies PHMSA, in accordance with § 192.18. For gas transmission, offshore gathering, and Types A, B, and C gathering pipelines located in Class 1 or Class 2 locations, an operator may use an alternative performance standard with prior notification to, and review by PHMSA in accordance with § 192.18. The notification must include: mileage by system type, known material properties, location, HCAs, operating parameters, environmental conditions, leak history, and design specifications, including coating, cathodic protection status, and pipe welding or joining method, the proposed performance standard, any safety conditions such as increased survey frequency, the leak detection equipment, procedures, and leakage survey frequencies the operator proposes to employ, data on the sensitivity and the leak detection performance of the proposed alternative ALDP standard, and the gas transported by the pipeline.

In this proposed rule, an operator may request an extension of the leak repair deadline requirements for an individual grade 3 leak with advance notification to, and review by, PHMSA pursuant to § 192.18. The operator's notification must show that the delayed repair timeline would not result in an increased risk to public safety, as well as that either the required repair deadline is impracticable, or that remediation within the specified time frame would result in the release of more gas to the environment than would occur with continued monitoring. The notification must include: a description of the leaking facility including the location, material properties, the type of equipment that is leaking, and the operating pressure; a description of the leak and the leak environment, including gas concentration readings, leak rate if known, class location, nearby buildings, weather conditions, soil conditions, and other conditions that could affect gas migration, such as pavement; a description of the alternative repair schedule and a justification for the same; and proposed emissions mitigation methods and monitoring and repair schedule. PHMSA estimates that it may receive 508 requests to extend the deadline for remedying leaks on average per year (341 from gas gathering operators and 167 from gas transmission operators), and that each of these requests would require approximately 8 hours to prepare.

Recordkeeping Requirements

PHMSA proposes to require operators to develop and maintain various records in conjunction with the proposed requirements in this NPRM. Among those requirements, operators must develop written procedures for grading and repairing leaks according to § 192.760(a)(1); operators must document post-repair evaluations according to § 192.760(e); operators must record the history of each leak, including leak discovery, grading, monitoring, remediation, upgrades, and downgrades, and maintain these records for a period of 5 years (records of repairs must be maintained for the life of the pipeline) pursuant to § 192.760(i)(1) and (2); operators must document the leak detection equipment choice analysis required in § 192.763(f); operators must also record leak detection equipment calibration (and re-calibration) and maintain these records for the life of the equipment pursuant to § 192.763(h)(2); and operators must record the repair or replacement of a pressure relief device and maintain these records for the life of the pipeline according to § 192.773(c). PHMSA estimates that it would take operators, on average, 80 hours annually to develop these records. PHMSA estimates that it would take operators 20 hours annually to maintain these records. This burden would be incurred by the total reporting community.

PHMSA will submit the following information collection requests to OMB for approval based on the requirements in this proposed rule. These information collections are contained in the pipeline safety regulations, 49 CFR parts 190 through 199. The following information is provided for each information collection: (1) Title of the information collection; (2) OMB control number; (3) Current expiration date; (4) Type of request; (5) Abstract of the information collection activity; (6) Description of affected public; (7) Estimate of total annual reporting and recordkeeping burden; and (8) Frequency of collection. The information collection burden for the following information collections are estimated to be revised as follows:

1. Title: Incident and Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0522.

Current Expiration Date: 03/31/2025.

Abstract: This mandatory information collection covers the collection of data from operators of natural gas pipelines, UNGSFs, and LNG facilities for annual reports. 49 CFR 191.17 requires operators of UNGSFs, gas transmission systems, and gas gathering systems to submit an annual report by March 15, for the preceding calendar year. This information collection also covers the collection of immediate notice of incident report data from Gas pipeline operators.

PHMSA proposes to revise this information collection in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM. The requested revision would revise form F7100.2–1, the ''Natural and Other Gas Transmission and Gathering Pipeline Systems Annual Report'' form, to collect the total number of leaks identified within a calendar year.

PHMSA currently estimates that 1,810 operators spend, on average, 47 hours completing form PHMSA F7100.2–1. PHMSA expects these operators to spend an additional 6 hours reporting the newly requested data on the total number of leaks identified and estimated emissions within the calendar year. This would increase the burden, per operator, from 47.5 hours annually to 53.5 hours annually to complete form PHMSA F7100.2–1. This revision would result in an additional reporting burden of 10,860 hours annually bringing the overall burden for completing form F7100.2–1 to 96,835 hours (53.5 hours × 1,810 responses).

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,321.

Total Annual Burden Hours: 106,671 hours.

Frequency of Collection: Annual.

2. Title: Annual Report for Gas Distribution Operators.

OMB Control Number: 2137–0629.

Current Expiration Date: 05/31/2024.

Abstract: This information collection request would require operators of gas distribution pipeline systems to submit annual report data to the Office of Pipeline Safety in accordance with the regulations stipulated in 49 CFR part 191 by way of form PHMSA F 7100.1–1. The form is to be submitted once for each calendar year. The annual report form collects data about the pipe material, size, and age. The form also collects data on leaks from these systems as well as excavation damages. PHMSA uses the information to track the extent of gas distribution systems and normalize incident and leak rates. PHMSA proposes to revise this information collection in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM. The requested revision would revise form PHMSA F7100.1–1, the Gas Distribution Annual Report, to collect the total number of leaks identified within a calendar year, emissions from leaks by grade, and estimated emissions from other sources by source categories.

PHMSA estimates that, currently, 1,446 operators spend 17.5 hours completing the Gas Distribution Annual report each year. PHMSA expects these operators to spend an additional 6 hours reporting the newly requested data on the total number of leaks identified and estimated emissions within the calendar year. Because of this, PHMSA expects the burden for completing form PHMSA F7100.1–1 to increase to 23.5 (17.5+6) hours per report adding a total of 8,676 (6 hours × 1,446 operators) hours to the overall burden for this information collection.

Affected Public: Gas Distribution operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 1,446.

Total Annual Burden Hours: 33,981.

Frequency of Collection: Annual.

3. Title: Reporting Safety-Related Conditions on Gas, Hazardous Liquid, and Carbon Dioxide Pipelines and Liquefied Natural Gas Facilities.

OMB Control Number: 2137–0578.

Current Expiration Date: 01/31/2023.

Abstract: 9 U.S.C. 60102 requires each operator of a pipeline facility (except master meter operators) to submit to DOT a written report on any safety-related condition that causes or has caused a significant change or restriction in the operation of a pipeline facility or a condition that is a hazard to life, property, or the environment. PHMSA proposes to adjust the burden associated with this information collection in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM which exempts large-volume gas releases from safety-related condition reporting. The requested revision would reduce the burden for this information collection by 3 responses and 18 burden hours annually. PHMSA is not proposing to collect any additional data at this time.

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 171.

Total Annual Burden Hours: 1,026.

Frequency of Collection: Annual.

4. Title: Incident and Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0635.

Current Expiration Date: 01/31/2023.

Abstract: Operators of natural gas pipelines and LNG facilities are required to report incidents, on occasion, to PHMSA per the requirements in 49 CFR part 191. This mandatory information collection covers the collection of incident report data from natural gas pipeline operators. The reports contained within this information collection support the Department of Transportation's strategic goal of safety. This information is an essential part of PHMSA's overall effort to minimize natural gas transmission, gathering, and distribution pipeline failures. PHMSA proposes to revise this information in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM to include a new form, (PHMSA F 7100.5) designed to collect data on intentional and unintentional releases of gas with a volume of 1 MMCF or greater.

PHMSA estimates that it would receive 593 of these new reports on average each year (139 gas transmission, 254 gas gathering, and 200 gas distribution), with each report estimated to require 12 hours to prepare. This would result in an additional 593 responses and 7,116 burden hours for this information collection.

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 1,592.

Total Annual Burden Hours: 11,572.

Frequency of Collection: On Occasion.

5. Title: National Pipeline Mapping System Program.

OMB Control Number: 2137–0596.

Expiration Date: 1/31/2023.

Type of Request: Revision of a previously approved information collection.

Abstract: The Pipeline Safety Improvement Act of 2002 (Pub. L. 107–355), 49 U.S.C. 60132, ''National Pipeline Mapping System,'' requires the operator of a pipeline facility (except distribution lines and gathering lines) to provide information to PHMSA. Each operator is required to submit geospatial data appropriate for use in the NPMS or data in a format that can be readily converted to geospatial data; the name and address of the person with primary operational control (to be known as its operator), and a means for a member of the public to contact the operator for additional information about the pipeline facilities it operates. Operators would submit the requested data elements once and make annual updates to the data if necessary. These data elements strengthen the effectiveness of PHMSA's risk rankings and evaluations, which are used as a factor in determining pipeline inspection priority and frequency; allow for more effective assistance to emergency responders by providing them with a more reliable, complete data set of pipelines and facilities; and provide better support to PHMSA's inspectors by providing more accurate pipeline locations and additional pipeline-related geospatial data that can be linked to tabular data in PHMSA's inspection database.

PHMSA proposes to revise this information in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM to require gas gathering operators to be subject to NPMS reporting. PHMSA estimates that gas transmission operators currently spend approximately 120 hours each year submitting geospatial data through the NPMS. PHMSA estimates that, due to the changes in this NPRM, 378 Type A, B, and C operators would be added to the NPMS reporting community. This addition would increase the number of responses for this information collection by 378 and increase the overall reporting burden by 45,360 hours.

Respondents: Operators of gas transmission, hazardous liquid, or LNG pipeline facilities.

Annual Reporting and Recordkeeping Burden:

Estimated Number of Responses: 1,724 responses.

Estimated Total Annual Burden: 207,761 hours.

Frequency of Collection: Annually.

6. Title: Notification Requirements for Leak Detection and Repair.

OMB Control Number: PHMSA will request a new OMB Control No.

Current Expiration Date: TBD.

Abstract: A person owning or operating a natural gas pipeline facility is required to provide information to the Secretary of Transportation at the Secretary's request according to 49 U.S.C. 60117. The Pipeline Safety regulations contained within 49 CFR part 192 require operators to make various notifications upon the occurrence of certain events. The provisions covered under this ICR involve notification requirements for operators who utilize alternative or expanded technologies and methods when conducting leak detection and repair activities. These notification requirements are necessary to ensure safe operation of pipelines and ascertain compliance with gas pipeline safety regulations. These mandatory notifications help PHMSA to stay abreast of issues related to the health and safety of the nation's pipeline infrastructure.

PHMSA proposes to create this information in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM which requires operators to notify PHMSA in various instances pertaining to leak detection and repair activities. PHMSA expects all gas pipeline operators to be subject to these notification requirements. PHMSA estimates that it may receive 1,000 requests on average per year from gas distribution operators to extend the deadline for remedying leaks, with each of these requests requiring approximately 8 hours to prepare.

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 1,000.

Total Annual Burden Hours: 8,000.

Frequency of Collection: On Occasion.

7. Title: Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 3/31/2025.

Abstract: A person owning or operating a natural gas pipeline facility is required to maintain records, make reports, and provide information to the Secretary of Transportation at the Secretary's request. This mandatory information collection request would require owners and/or operators of gas pipeline systems to make and maintain records in accordance with the requirements prescribed in 49 CFR part 192 and to provide information to the Secretary of Transportation at the Secretary's request. Certain records are maintained for a specific length of time while others are required to be maintained for the life of the pipeline. PHMSA uses these records to verify compliance with regulated safety standards and to inform the agency on possible safety risks.

PHMSA proposes to revise this information in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM which includes various recordkeeping requirements for operators pertaining to leak detection and remediation activities.

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,867,101 responses.

Total Annual Burden Hours: 1,904,157 hours.

Frequency of Collection: On Occasion.

Requests for copies of these information collections should be directed to Angela Hill at *angela.hill@dot.gov.* Comments are invited on:

(a) The need for the proposed collection of information for the proper performance of the functions of the agency, including whether the information will have practical utility;

(b) The accuracy of the agency's estimate of the burden of the revised collection of information, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(d) Ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques.

Send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street NW, Washington, DC 20503. Comments should be submitted on or prior to July 17, 2023.

J. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act (UMRA, 2 U.S.C. 1501 *et seq.*) requires agencies to assess the effects of Federal regulatory actions on State, local, and Tribal governments, and the private sector. For any NPRM or final rule that includes a Federal mandate that may result in the expenditure by state, local, and Tribal governments, in the aggregate of $100 million or more (in 1996 dollars) in any given year, the agency must prepare, amongst other things, a written statement that qualitatively and quantitatively assesses the costs and benefits of the Federal mandate.

PHMSA expects this NPRM would impose compliance costs of $100 million or more (in 1996 dollars) on private sector entities. PHMSA has conducted an assessment (within the Preliminary RIA in the rulemaking docket) of the NPRM and has preliminarily concluded that the NPRM's proposed regulatory amendments will yield an appropriate balancing of costs and benefits.

K. Privacy Act Statement

In accordance with 5 U.S.C. 553(c), PHMSA solicits comments from the public to better inform its rulemaking process. PHMSA posts these comments, without edit, including any personal information the commenter provides, to *www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *www.dot.gov/privacy.*

L. Executive Order 13609 and International Trade Analysis

E.O. 13609 (''Promoting International Regulatory Cooperation'') [308] requires agencies consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements.

Similarly, the Trade Agreements Act of 1979 (Pub. L. 96–39), as amended by the Uruguay Round Agreements Act (Pub. L. 103–465), prohibits Federal

[308] 77 FR 26413 (May 4, 2012).

agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. For purposes of these requirements, Federal agencies may participate in the establishment of international standards, so long as the standards have a legitimate domestic objective, such as providing for safety, and do not operate to exclude imports that meet this objective. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards.

PHMSA engages with international standards setting bodies to protect the safety of the American public. PHMSA has assessed the effects of the NPRM and has preliminarily determined that its proposed regulatory amendments would not cause unnecessary obstacles to foreign trade.

M. Cybersecurity and Executive Order 14082

E.O. 14082 (''Improving the Nation's Cybersecurity'') [309] expressed the Administration policy that ''the prevention, detection, assessment, and remediation of cyber incidents is a top priority and essential to national and economic security.'' E.O. 14082 directed the Federal Government to improve its efforts to identify, deter, and respond to ''persistent and increasingly sophisticated malicious cyber campaigns.'' In keeping with these policies and directives, PHMSA has assessed the effects of this NPRM to determine what impact the proposed regulatory amendments may have on cybersecurity risks for pipeline facilities.

PHMSA's proposed requirements would not require pipeline operators to generate new security-sensitive records. Most of the pipeline facilities for which PHMSA proposes leak detection and repair requirements (and associated recordkeeping requirements) are already subject to such requirements—this NPRM simply proposes to enhance and expand those requirements. While computerized continuous or remote monitoring systems for pipeline facilities could be more vulnerable to cyber-attack than other technologies, the NPRM does not prescribe the use of any particular leak detection technology within operator advanced leak detection programs. PHMSA proposes to require operators to evaluate remote and real-time leak detection technologies as one potential approach when operators are designing the portfolio of technologies to be used to satisfy the proposed ALDP requirements, but ultimately operators can choose to adopt or decline such technologies.

One proposal that may present relatively more cybersecurity risk is the proposed requirement for offshore gas gathering pipelines and Types A, B, and C gas gathering pipelines to provide geospatial data for NPMS. If hacked by a bad actor, this information could provide particularly sensitive information regarding the location of gas gathering infrastructure nationwide. However, the risk associated with hacking of NPMS data on gas gathering infrastructure appears relatively low compared to the risks associated with unauthorized release of NPMS data on gas transmission infrastructure. Data on gas transmission infrastructure has long been stored in NPMS and would likely be considered a more attractive target for bad actors given the greater importance of transmission lines in the U.S. interstate gas supply network.

Operators affected by these proposed requirements may also be subject to cybersecurity requirements and guidance under Transportation Security Administration (TSA) Security Directives,[310] as well as any new requirements resulting from ongoing TSA efforts to strengthen cybersecurity and resiliency in the pipeline sector, as discussed within an advance notice of proposed rulemaking published in November 2022.[311] The Cybersecurity & Infrastructure Security Agency (CISA) and the Pipeline Cybersecurity Initiative (PCI) of the U.S. Department of Homeland Security also conduct ongoing activities to address cybersecurity risks to U.S. pipeline infrastructure and may introduce other cybersecurity requirements and guidance for gas pipeline operators.[312]

PHMSA has considered the effects of the NPRM and has preliminarily determined that its proposed regulatory amendments would not materially affect the cybersecurity risk profile for pipeline facilities within the scope of the proposed amendments. PHMSA seeks comment on any other potential cybersecurity impacts of the proposed amendments beyond the considerations discussed here.

N. Severability

The purpose of this proposed rule is to operate holistically in addressing a panoply of issues related to safety and environmental hazards on regulated pipelines, with a focus on detection, grading, and repair of leaks. However, PHMSA recognizes that certain provisions focus on unique topics. Therefore, PHMSA preliminarily finds that the various provisions of this proposed rule are severable and able to function independently if severed from each other, and thus, in the event a court were to invalidate one or more of this proposed rule's unique provisions, the remaining provisions should stand and continue in effect. PHMSA seeks comment on which portions of this proposed rule should or should not be severable.

List of Subjects

49 CFR Part 191

Natural gas, Pipeline safety, Reporting and recordkeeping requirements.

49 CFR Part 192

Natural gas, Pipeline safety, Safety.

49 CFR Part 193

Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, PHMSA proposes to amend 49 CFR parts 191, 192, and 193 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

■ 1. The authority citation for part 191 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5121, 60101 *et. seq.,* and 49 CFR 1.97.

■ 2. In § 191.3:
■ a. Revise paragraph (1)(ii) in the definition of ''Incident''; and
■ b. Add the definition of ''Large-volume gas release'' in alphabetical order.

The revision and addition read as follows:

§ 191.3 Definitions.

* * * * *

Incident * * *

(1) * * *

(ii) Estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding each of the cost of gas lost, the cost to acquire permits, and the cost to remove and replace non-operator infrastructure that was not damaged by the release. For adjustments for inflation

[309] 86 FR 26633 (May 17, 2021).

[310] *E.g.,* TSA, ''Ratification of Security Directive,'' 86 FR 38209 (July 20, 2021) (ratifying TSA Security Directive Pipeline–2012–01, which requires certain pipeline owners and operators to conduct actions to enhance pipeline cybersecurity).

[311] TSA, ''Enhancing Surface Cyber Risk Management,'' 87 FR 74702 (Nov. 30, 2022).

[312] *See, e.g.,* CISA, National Cyber Awareness System Alerts, *https://www.cisa.gov/uscert/ncas/alerts* (last accessed Feb. 1, 2023).

observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191.

* * * * *

Large-volume gas release means 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.

* * * * *

■ 3. Add § 191.19 to read as follows:

§ 191.19 Large-volume gas release report.

Each operator of a gas pipeline facility must report a large-volume gas release on DOT Form PHMSA–F7100.5. Each report must be submitted within 30 days after detection of a large-volume gas release. A large-volume gas release report is not required if an incident report has already been submitted under this part 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.

■ 4. In § 191.23, revise paragraphs (a)(9) and (b)(2) to read as follows:

§ 191.23 Reporting safety-related conditions.

(a) * * *

(9) Any safety-related condition that could lead to an imminent hazard to public safety and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20% or more reduction in operating pressure or shutdown of operation of a pipeline, UNGSF, or an LNG facility that contains or processes gas or LNG.

* * * * *

(b) * * *

(2) Is an incident or large-volume gas release, or results in an incident or large-volume gas release before the deadline for filing the safety-related condition report;

* * * * *

■ 5. In § 191.29, revise paragraph (a) introductory text, and remove paragraph (c) to read as follows:

§ 191.29 National Pipeline Mapping System.

(a) Each operator of a gas transmission pipeline, offshore gathering, Type A, Type B, or Type C regulated onshore gathering pipeline as determined in § 192.8 of this subchapter, or liquefied natural gas facility must provide the following geospatial data to PHMSA for that pipeline or facility:

* * * * *

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 6. The authority citation for part 192 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 et seq., and 49 CFR 1.97.

■ 7. In § 192.3, add the definitions of ''Confined space,'' ''Gas-associated substructure,'' ''Leak or hazardous leak,'' ''Lower explosive limit (LEL),'' ''Substructure,'' ''Tunnel,'' and ''Wall-to-wall paved area'' in alphabetical order to read as follows:

§ 192.3 Definitions.

* * * * *

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

* * * * *

Gas-associated substructure means a substructure that is part of an operator's pipeline but that is not itself designed to contain gas.

* * * * *

Leak or hazardous leak means, for the purposes of all subparts of part 192 except § 192.12(d) and subparts O and P, 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.

* * * * *

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

* * * * *

Substructure means any subsurface structure that is not large enough for a person to enter and in which gas could accumulate or migrate. Substructures include, but are not limited to, telephone and electrical ducts, and conduit, gas and water valve boxes, and meter boxes.

* * * * *

Tunnel is a subsurface passageway large enough for a person to enter and in which gas could accumulate or migrate.

* * * * *

Wall-to-wall paved area means an area where the ground surface between the curb of a paved street and the front wall of a building is continuously paved, excluding intermittent landscaping, such as tree plots.

* * * * *

■ 8. In § 192.9:
■ a. Revise paragraph (b);
■ b. Redesignate paragraphs (d)(4) through (8) as paragraphs (d)(6) through (10);
■ c. Add new paragraphs (d)(4) and (5);
■ d. Remove the word ''and'' from the end of paragraph (d)(9);
■ e. Revise newly redesignated paragraph (d)(10), and add paragraphs (d)(11) through (13);
■ f. Redesignate paragraphs (e)(1)(iii) through (vii) as paragraphs (e)(1)(iv) through (viii);
■ g. Add new paragraph (e)(1)(iii);
■ h. Remove the word ''and'' at the end of paragraph (e)(1)(vii);
■ i. Revise newly redesignated paragraph (e)(1)(viii);
■ j. Add paragraphs (e)(1)(ix) through (xi); and
■ k. Revise paragraph (f).

The revisions and additions read as follows:

§ 192.9 What requirements apply to gathering pipelines?

* * * * *

(b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), 192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, 192.714, 192.763(c)(1)(vi) and (c)(3), and in subpart O of this part.

* * * * *

(d) * * *

(4) Prepare, update, and follow a manual of written procedures for conducting operations, maintenance, and emergency response in accordance with § 192.605. Compliance with the requirements referenced in § 192.605(b)(1), (b)(2), (b)(12), and (e) is only required for pipeline facilities that are made subject to such requirements under this section or § 191.23;

(5) Develop and implement procedures for emergency plans in accordance with § 192.615;

* * * * *

(10) Conduct leakage surveys in accordance with § 192.706 within an advanced leak detection program in accordance with § 192.763;

(11) Investigate, grade, repair, and document leaks and leak repairs in accordance with §§ 192.703(c) through (d), 192.709, and 192.760;

(12) Conduct patrols in accordance with § 192.705; and

(13) Maintain and configure pressure relief devices to ensure proper device operation and minimize release of gas in accordance with § 192.773.

(e) * * *

(1) * * *

(iii) Prepare, update, and follow a manual of written procedures for conducting operations, maintenance, and emergency response in accordance with § 192.605. Compliance with the requirements referenced in § 192.605(b)(1), (2) and (12), (d), and (e) is only required for pipeline facilities that are made subject to such requirements under this section or § 191.23;

* * * * *

(viii) Conduct leakage surveys in accordance with §§ 192.706 within an advanced leak detection program in accordance with § 192.763;

(ix) Grade, investigate, repair, and document leaks and leak repairs in accordance with §§ 192.703(c) and (d), 192.709, and 192.760;

(x) Conduct patrols in accordance with § 192.705; and

(xi) Maintain and configure pressure relief devices to ensure proper device operation and minimize release of gas in accordance with § 192.773.

* * * * *

(f) *Exceptions.* (1) Compliance with paragraphs (e)(1)(ii), (vi), and (vii), and (e)(2)(i) and (ii) of this section is not required for pipeline segments that are 16 inches or less in outside diameter if one of the following criteria are met:

* * * * *

■ 9. In § 192.12, revise paragraph (c) to read as follows:

§ 192.12 Underground natural gas storage facilities.

* * * * *

(c) *Procedural manuals.* Each operator of an UNGSF must prepare and follow for each facility one or more manuals of written procedures for conducting operations, maintenance, and emergency preparedness and response activities under paragraphs (a) and (b) of this section. Such manuals must include procedures for eliminating leaks and minimizing releases of gas. Each operator must keep records necessary to administer such procedures and review and update these manuals at intervals not exceeding 15 months, but at least once each calendar year. Each operator must keep the appropriate parts of these manuals accessible at locations where UNGSF work is being performed. Each operator must have written procedures in place before commencing operations or beginning an activity not yet implemented.

* * * * *

■ 10. In § 192.18, revise paragraph (c) to read as follows:

§ 192.18 How to notify PHMSA.

* * * * *

(c) Unless otherwise specified, if an operator submits, pursuant to § 192.8, 192.9, 192.13, 192.179, 192.319, 192.461, 192.506(b), 192.607(e)(4), 192.607(e)(5), 192.619, 192.624(c)(2)(iii), 192.624(c)(6),192.632(b)(3), 192.634, 192.636, 192.703(d)(4), 192.706(a)(2), 192.710(c)(7), 192.712(d)(3)(iv), 192.712(e)(2)(i)(E), 192.714, 192.745, 192.760(h), 192.763(c), 192.917, 192.921(a)(7), 192.927, 192.933, or 192.937(c)(7) a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*e.g.,* ''other technology'' or ''alternative equivalent technology'') than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from PHMSA informing the operator that PHMSA objects to the proposal or that PHMSA requires additional time and/or more information to conduct its review.

* * * * *

■ 11. In § 192.167, revise paragraph (a)(2) to read as follows:

§ 192.167 Compressor stations: Emergency shutdown.

(a) * * *

(2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard to public safety;

* * * * *

■ 12. In § 192.169, revise paragraph (b) as follows:

§ 192.169 Compressor stations: Pressure limiting devices.

* * * * *

(b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard to public safety.

* * * * *

■ 13. In § 192.179, revise paragraph (c) to read as follows:

§ 192.179 Transmission line valves.

* * * * *

(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard to public safety and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

* * * * *

■ 14. In § 192.199, revise the section heading and paragraph (e), and add paragraph (i) to read as follows:

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

* * * * *

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

* * * * *

(i) All new, replaced, relocated, or otherwise changed pressure relief and limiting devices must be designed and configured, as demonstrated by a documented engineering analysis, to minimize unnecessary releases of gas by ensuring each of the following:

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

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

(3) Installation of the pressure relief device must include upstream and downstream isolation valves to facilitate testing and maintenance.

■ 15. In § 192.361, revise paragraph (f)(3) to read as follows:

§ 192.361 Service lines: Installation.

* * * * *

(f) * * *

(3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard to public safety, and

extend above grade, terminating in a rain and insect resistant fitting.

* * * * *

■ 16. In § 192.363, revise paragraph (c) to read as follows:

§ 192.363 Service lines: Valve requirements.

* * * * *

(c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous to public safety, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

■ 17. In § 192.503 revise paragraph (a)(2) to read as follows:

§ 192.503 General requirements.

(a) * * *

(2) Each hazardous leak has been located and eliminated.

* * * * *

■ 18. In § 192.507, revise paragraph (a) to read as follows:

§ 192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.

* * * * *

(a) The pipeline operator must use a test procedure that will ensure discovery of all hazardous leaks in the segment being tested.

* * * * *

■ 19. In § 192.509, revise paragraph (a) to read as follows:

§ 192.509 Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.

* * * * *

(a) The test procedure used must ensure discovery of all hazardous leaks in the segment being tested.

* * * * *

■ 20. In § 192.513, revise paragraph (b) to read as follows:

§ 192.513 Test requirements for plastic pipelines.

* * * * *

(b) The test procedure must ensure discovery of all hazardous leaks in the segment being tested.

* * * * *

■ 21. In § 192.553, revise paragraph (a)(2) to read as follows:

§ 192.553 General requirements.

* * * * *

(a) * * *

(2) Each leak detected must be repaired before a further pressure increase is made.

* * * * *

■ 22. In § 192.557, revise paragraph (b)(2) to read as follows:

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

* * * * *

(b) * * *

(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found.

* * * * *

■ 23. In § 192.605, add paragraph (b)(13) to read as follows:

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

* * * * *

(b) * * *

(13) Eliminating leaks and minimizing releases of gas from pipelines, as well as remediating or replacing pipelines known to leak based on their material, design, or past operating and maintenance history.

* * * * *

■ 24. In § 192.617, add paragraph (e) to read as follows:

§ 192.617 Investigation of failures and incidents.

* * * * *

(e) *Failure defined.* For the purposes of this section, the term failure means 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.

■ 25. In § 192.629, revise paragraphs (a) and (b) to read as follows:

§ 192.629 Purging of pipelines.

(a) When a pipeline is being purged of air by use of gas, the gas must be introduced into one end of the pipeline in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a mixture of gas and air hazardous to public safety, a slug of inert gas must be introduced into the pipeline before the gas.

(b) When a pipeline is being purged of gas by use of air, the air must be introduced into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a mixture of gas and air hazardous to public safety, a slug of inert gas must be released into the line before the air.

■ 26. In § 192.703, revise paragraph (c), and add paragraph (d) to read as follows:

§ 192.703 General.

* * * * *

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

(d) Compliance with §§ 192.703(c), 192.705 for patrols, 192.706 for leakage surveys, 192.760(a) through (h) for leak grading and repair, 192.763 for advanced leak detection programs, and 192.769 for qualification of leakage survey personnel, is not required for a compressor station on a gas transmission or gathering pipeline if:

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

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

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

(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).

■ 27. In § 192.705, revise paragraph (b) to read as follows:

§ 192.705 Transmission lines: Patrolling.

* * * * *

(b) Operators must conduct patrols at least 12 times each calendar year at intervals not exceeding 45 days.

* * * * *

■ 28. Revise § 192.706 to read as follows:

§ 192.706 Transmission lines: Leakage surveys.

(a) *General.* Each operator must perform periodic leakage surveys in accordance with this section. Each leakage survey must be conducted according to the advanced leak detection program requirements in § 192.763, except that human or animal senses may be used in lieu of leak detection equipment only in the following circumstances:

(1) An offshore gas transmission pipeline below the waterline or offshore gathering pipeline below the waterline; or

(2) An onshore transmission line outside of an HCA or a gathering pipeline, each either in a Class 1 or Class 2 location, with advance notification to PHMSA in accordance with § 192.18. The notification must include tests or analyses demonstrating that the survey method would meet the ALDP performance standard in § 192.763(b) or (c) (as applicable).

(b) *Frequency of surveys.* Except as provided in paragraphs (c) and (d) of this section, leakage surveys must be performed at the following intervals:

(1) Pipelines outside of HCAs must be surveyed at least once per calendar year, but with an interval between surveys not to exceed 15 months; and

(2) Pipelines in HCAs must be surveyed as follows:

(i) In Class 1, Class 2, and Class 3 locations, at least twice each calendar year, with intervals not exceeding 7½ months;

(ii) In Class 4 locations, at least four times each calendar year, with intervals not exceeding 4½ months.

(c) *Non-odorized pipelines.* Leakage surveys for pipelines transporting gas in conformity with § 192.625 without an odor or odorant, must perform leakage surveys using leak detection equipment at the following intervals:

(1) In Class 3 locations, at least twice each calendar year, at intervals not exceeding 7½ months.

(2) In Class 4 locations, at least four times each calendar year, at intervals not exceeding 4½ months.

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

(1) In Class 1, Class 2, and Class 3 locations, at least twice each calendar year, at intervals not exceeding 7½ months.

(2) In Class 4 locations, at least four times each calendar year, at intervals not exceeding 4½ months.

■ 29. Revise § 192.723 to read as follows:

§ 192.723 Distribution systems: Leakage surveys.

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

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

(c) *Non-business districts.* Leakage surveys must be conducted at least once every 3 calendar years, at intervals not exceeding 39 months, unless a shorter inspection interval is required either by paragraph (d) of this section, the operator's operations and maintenance procedures, or the operator's integrity management plans under part 192, subpart P.

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

(1) Cathodically unprotected distribution pipelines subject to § 192.465(e);

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

(3) Gas distribution pipeline systems protected by a distributed anode system, in the area of deficient readings identified during a cathodic protection survey pursuant to § 195.463 and appendix D, until the cathodic protection deficiency is remediated.

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

(f) *Extreme Weather Surveys.* Leakage surveys must be performed after extreme weather events and land movement with the likelihood to cause damage to the affected pipeline segment. The survey must be initiated within 72 hours after the cessation of the event, defined as either the point in time when the affected area can be safely accessed by the personnel and equipment required to perform the leakage survey or when the facility has been returned to service.

■ 30. In § 192.727, revise paragraphs (b) and (c) to read as follows:

§ 192.727 Abandonment or deactivation of facilities.

* * * * *

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard to public safety.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard to public safety.

* * * * *

■ 31. In § 192.751, revise paragraph (a) to read as follows:

§ 192.751 Prevention of accidental ignition.

* * * * *

(a) When an amount of gas potentially hazardous to public safety is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be present.

* * * * *

■ 32. Add § 192.760 to read as follows:

§ 192.760 Leak grading and repair.

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

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

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

(3) Each leak must be investigated immediately and continuously until a leak grade determination has been made.

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

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

(ii) Any amount of escaping gas has ignited;

(iii) Any indication that gas has migrated into a building, under a building, or into a tunnel;

(iv) Any reading of gas at the outside wall of a building, or areas where gas could migrate to an outside wall of a building;

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

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

(vii) Any leak that can be seen, heard, or felt; or

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

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

(i) Implementing an emergency plan pursuant to § 192.615;

(ii) Evacuating premises;

(iii) Blocking off an area;

(iv) Rerouting traffic;

(v) Eliminating sources of ignition;

(vi) Venting the area by removing manhole covers, bar holing, installing vent holes, or other means;

(vii) Stopping the flow of gas by closing valves or other means; or

(viii) Notifying emergency responders.

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

(i) A reading of 40% or greater of the LEL under a sidewalk in a wall-to-wall paved area that does not qualify as a grade 1 leak;

(ii) A reading at or above 100% of LEL under a street in a wall-to-wall paved area that has gas migration and does not qualify as a grade 1 leak;

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

(iv) A reading less than 80% of the LEL in a substructure (other than gas associated substructures) from which gas could migrate;

(v) A reading of 80% or greater of the LEL in a gas associated substructure from which gas could not migrate;

(vi) Any reading of gas that does not qualify as a grade 1 leak that occurs on a transmission pipeline or a Type A or Type C regulated gas gathering line;

(vii) Any leak with a leakage rate of 10 cubic feet per hour (CFH) or more that does not qualify as a grade 1 leak;

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

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

(2) An operator must schedule repair based on the severity or likelihood of hazard to persons, property, or the environment. A grade 2 leak must be repaired within six months of detection, unless a shorter repair deadline is required by the operator's procedures, integrity management program, or paragraphs (c)(3) through (6) of this section. The operator must re-evaluate each grade 2 leak at least once every 30 days until it is repaired.

(3) The operator must complete repair of any grade 2 leak on a gas transmission or Type A gathering pipeline, each located in an HCA, Class 3 or Class 4 location, within 30 days of detection. If repair cannot be completed within 30 days due to permitting requirements or parts availability, the operator must take continuous action to monitor and repair the leak.

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

(i) The volume and migration of gas emissions;

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

(iii) The extent of pavement; and

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

(5) Each operator must take immediate and continuous action to complete repair of a grade 2 leak and eliminate the hazard when freezing ground, heavy rain, flooding, new pavement, or other changes to the environment are anticipated or occur near an existing grade 2 leak that may affect the venting or migration of gas and could allow gas to migrate to the outside wall of a building.

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

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

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

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

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

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

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

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

(3) Each operator must re-evaluate each grade 3 leak at least once every six months until repair of the leak is complete.

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

(2) An operator must conduct a post-repair leak inspection at least 14 days after but no later than 30 days after the date of the repair to determine if the repair was complete.

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

(i) If the post repair inspection finds gas concentrations or migration indicating that the potential for a grade 1 or grade 2 condition leak exists, the operator must re-inspect the repair and take immediate and continuous action to eliminate the hazard and complete repair;

(ii) If the operator's post repair inspection does not find a gas concentration reading of 0% at the leak location, and a grade 1 or grade 2 condition does not exist, then the operator must remediate the repair and re-inspect the leak within 30 days and continue reevaluating the leak at least once every 30 days until there is a gas concentration reading of 0%. Leak repair must be complete within the repair deadline for a grade 3 leak under § 192.760(d)(2), or for a downgraded leak, the repair deadline under § 192.760(g).

(4) A post repair inspection is not required for any leak that is eliminated by routine maintenance work—such as adjustment or lubrication of aboveground valves, or tightening of packing nuts on valves with seal leaks—and is a grade 3 leak or occurs on an aboveground pipeline facility.

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

(g) *Downgrading leak grades.* A leak may not be downgraded to a lower-priority leak grade unless a temporary repair to the pipeline has been made or a permanent repair was attempted but gas was detected during the post-repair inspection under paragraph (e) of this section. In this case, the time period for repair is the remaining time allowed for repair under its new grade measured from the time the leak was detected.

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

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

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

(3) A description of the alternative repair schedule and a justification for the same; and

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

(i) *Recordkeeping.* (1) Records of the complete history of the investigation and grading of each leak must be retained for 5 years after the final post-repair inspection is completed under paragraph (e) of this section. These records include all records documenting leak grading, monitoring, inspections, upgrades, and downgrades.

(2) Records of the detection, remediation, and repair of the leak must be retained for the life of the pipeline. This must include the date, location, and description of each leak detected, and repair or remediation of the same, made on the pipeline.

■ 33. Add § 192.763 to read as follows:

§ 192.763 Advanced Leak Detection Program.

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

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

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

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

(A) The use of handheld leak detection equipment capable of detecting and locating all leaks of 5 parts per million or more when measured within 5 feet of the pipeline or within a wall-to-wall paved area, in conjunction with locating equipment to verify the tools are sampling the area within 5 feet of the buried pipeline. The procedure must include sampling the atmosphere near cracks, vaults, or any other surface feature where gas could migrate;

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

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

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

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

(2) *Leak detection practices.* At a minimum, an operator must have and follow written procedures for:

(i) *Performing leakage surveys.* Operators must have procedures for performing leakage surveys required for §§ 192.706 and 192.723 using each selected leak detection technology as described in paragraph § 192.763(a)(1). The procedures must define environmental and operational conditions for which each leak detection technology is and is not permissible. The operator's procedures must follow the leak detection equipment manufacturer's instructions for survey methods and allowable environmental and operational parameters.

(ii) *Pinpointing and investigating leaks.* The location of the source of each leak indication on an onshore pipeline or any portion of an offshore pipeline above the waterline must be pinpointed and investigated with handheld leak detection equipment. Leak indications on offshore pipelines below the waterline may be pinpointed with human senses.

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

(iv) *Maintaining and calibrating leak detection equipment.* At a minimum, procedures must follow the equipment manufacturer's instructions for calibration and maintenance. Leak detection equipment must be recalibrated or replaced following any indication of malfunction. Records validating equipment calibration and failures indicating recalibration is necessary must be maintained for 5 years after the date the individual device is retired by the operator.

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

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

(i) The operator must evaluate the ALDP at least once each calendar year but with a maximum interval not to exceed 15 months.

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

(iii) When considering changes to program elements, operators must analyze, at a minimum, the performance of the leak detection equipment used, the adequacy of the leakage survey procedures, advances in leak detection technologies and practices, the number of leaks that are initially detected by the public, the number of leaks and incidents, and estimated emissions from leaks detected pursuant to this section.

(iv) The operator must document any improvements needed to the program.

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

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

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

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

(1) Mileage by system type;

(2) Known material properties, location, HCAs, operating parameters, environmental conditions, leak history, and design specifications, including coating, cathodic protection status, and pipe welding or joining method;

(3) The proposed performance standard;

(4) Any safety conditions, such as increased survey frequency;

(5) The leak detection equipment, procedures, and leakage survey frequencies the operator proposes to employ;

(6) Data on the sensitivity and the leak detection performance of the proposed alternative ALDP standard; and

(7) The gas transported by the pipeline.

■ 34. Add § 192.769 to read as follows:

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

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

■ 35. Add § 192.770 to read as follows:

§ 192.770 Minimizing emissions from gas transmission pipeline blowdowns.

(a) Except as provided in paragraph (b) of this section, when an operator performs any intentional release of gas (including blowdowns or venting for scheduled repairs, construction, operations, or maintenance) from a gas transmission pipeline, the operator must prevent or minimize the release of gas to the environment through one or more of the following methods:

(1) Isolating the smallest section of the pipeline necessary to complete the task by use of valves or the installation of control fittings;

(2) Routing gas released from the pipeline from the nearest isolation valves or control fittings to a flare or to other equipment as fuel gas;

(3) Reducing pressure by use of in-line compression;

(4) Reducing pressure by use of mobile compression to a segment or storage vessel adjacent to the nearest isolation valves;

(5) Transferring the gas to a segment of a lower pressure pipeline system adjacent to the nearest isolation valves; or

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

(b) An operator is not required to comply with the provisions of paragraph (a) of this section during an event that activates its emergency plan under § 192.615(a)(3) when such minimization would delay emergency response or result in a safety risk during pipeline assessments or maintenance. Each emergency release conducted without mitigation must be documented, including the justification for release without mitigation.

(c) Operators must document the methodologies used in paragraph (a) of this section and describe how the methodologies minimize the release of gas to the environment.

■ 36. Add § 192.773 to read as follows:

§ 192.773 Pressure relief device maintenance and adjustment of configuration.

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

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

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

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

(i) If a pressure relief device activates above its set pressure and above the pressure limits in § 192.201(a) or 192.739 as applicable, fails to operate, or otherwise fails to provide overpressure protection, the operator must repair or replace the device or pressure sensing equipment immediately.

(ii) If a pressure relief device allows gas to release to the atmosphere at an operating pressure below the set actuation pressure range, the operator must take immediate and continuous action with on-site personnel to stop the release until the device is repaired or replaced. The relief device or pressure sensing equipment must be repaired or replaced as soon as practicable but within 30 days.

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

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

(1) Records of relief devices malfunctions must be maintained for 5 years after repair or replacement.

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

■ 37. In § 192.1007, revise paragraphs (e)(1)(i) and (v) as follows:

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

* * * * *

(e) * * *

(1) * * *

(i) Number of hazardous leaks either eliminated or repaired (or total number of leaks if all leaks are repaired when found), categorized by cause;

* * * * *

(v) Number of hazardous leaks either eliminated or repaired (or total number of leaks if all leaks are repaired when found), categorized by material; and

* * * * *

PART 193—LIQUEFIED NATURAL GAS FACILITIES: FEDERAL SAFETY STANDARDS

■ 38. The authority citation for part 193 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60103, 60104, 60108, 60109, 60110, 60113, 60118; and 49 CFR 1.53.

■ 39. In § 193.2503, add paragraph (h) to read as follows:

§ 193.2503 Operating procedures.

* * * * *

(h) Eliminating leaks and minimizing releases of gas.

■ 40. Add § 193.2523 to read as follows:

§ 193.2523 Minimizing emissions from blowdowns and boiloff.

(a) Except as provided in paragraph (b) of this section, an operator of an LNG facility must minimize intentional emissions of natural gas from LNG facilities, including tank boiloff or blowdowns for repairs, construction, operations, or maintenance. The operator must minimize the release of natural gas to the environment by use of one or more of the following methods:

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

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

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

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

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

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

■ 41. In § 193.2605, add paragraph (b)(3) to read as follows:

§ 193.2605 Maintenance procedures.

* * * * *

(b) * * *

(3) Procedures for eliminating leaks and minimizing releases of gas.

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■ 42. Add § 193.2624 to read as follows:

§ 193.2624 Leakage surveys.

(a) Each operator of an LNG facility, including mobile, temporary, and satellite facilities must conduct periodic methane leakage surveys, on equipment and components within their facilities containing methane or LNG, at least four times each calendar year, with a maximum interval between surveys not exceeding 4½ months, using leak detection equipment. Leak detection equipment must be capable of detecting and locating all methane leaks producing a reading of 5 parts per million or more of within 5 feet of the component or equipment surveyed.

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

(1) Validating the leakage survey equipment and performing leakage surveys consistent with the equipment manufacturer's instructions for survey methods and allowable environmental and operational parameters;

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

(3) Calibrating the equipment consistent with the equipment manufacturer's instructions for calibration and maintenance. Leak detection equipment must be recalibrated or replaced following any indication of malfunction.

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

(d) Operators must review the results of the methane leakage surveys and address any methane leaks and abnormal operating conditions in accordance with their written maintenance procedures or abnormal operating procedures.

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Alan K. Mayberry,

Associate Administrator for Pipeline Safety.

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