U.S. Department of Transportation

Pipeline and Hazardous Materials
Safety Administration
Washington, DC 20590

Preliminary Regulatory Impact Analysis

[Docket No. PHMSA-2021-0039]

Pipeline Safety: Gas Leak Detection and Repair

Proposed Rule

Office of Pipeline Safety

April 2023

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Executive Summary

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is proposing regulatory amendments that implement Congressional mandates in the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020) to reduce emissions of methane and other flammable, toxic, and corrosive gases[1] from new and existing gas transmission, distribution, and 49 CFR part 192-regulated gathering (Types A, B, and C) pipelines and other gas pipeline facilities, including liquefied natural gas (LNG) facilities and underground natural gas storage facilities (UNGSFs). 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 and mandatory repair timelines; and requirements for mitigation of emissions from blowdowns and pressure relief device design, configuration, and maintenance. The rulemaking also proposes enhanced reporting requirements for operators of all gas pipeline facilities within DOT's jurisdiction, including LNG facilities and UNGSFs.

Under Executive Order 12866, "Regulatory Planning and Review," as supplemented by Executive Order 13563, "Improving Regulation and Regulatory Review," the Pipeline and Hazardous Materials Safety Administration (PHMSA) is required to assess the costs and benefits of its regulatory actions. This Preliminary Regulatory Impact Analysis (PRIA) provides PHMSA's assessment of the costs and benefits of the proposed regulation. The accompanying draft Environmental Assessment (DEA) document complements the analysis of benefits presented in this PRIA by discussing environmental and other effects expected to result from the proposed rule (PHMSA, 2023).

Costs

Costs attributable to the proposed rule arise from requirements to conduct more frequent leak surveys and patrols, to use advanced leak detection equipment and procedures that result in more effective identification of gas leaks, to repair more of the existing leaks that are hazardous to safety and the environment and do so in a timelier fashion, and to develop and maintain records and report data to PHMSA. Table ES-1 summarizes the incremental costs for gas gathering, gas transmission, and gas distribution according to the major categories of compliance activities. These costs are relative to a baseline that accounts for current practices operators implement in accordance with federal and state regulations and industry standards.

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[1] Much of the discussion in the NPRM and in this Preliminary Regulatory Impact Assessment 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).

Table ES-1: Total annualized costs of proposed requirements (million 2020$, 3 percent discount rate)			
Industry Segment	**Requirement**	**Total annualized costs**	
Gathering	Patrols	$151.7	
	Leakage surveys	$41.5	
	Leak repairs	$15.1	
	NPMS reporting	$1.7	
	Other reporting and recordkeeping	$0.6	
	Total[1]	**$210.6**	
Transmission	Patrols	—	
	Leakage surveys	$12.2	
	Leak repairs	$1.5	
	Other reporting and recordkeeping	$1.2	
	Total[1]	**$14.9**	
Distribution	*Basis of estimates[2]*	*Low*	*High*
	Leakage surveys	$292.2	$292.2
	Leak repairs and monitoring	$219.6	$359.4
	Other reporting and recordkeeping	$2.4	$2.4
	Total[1]	**$514.2**	**$654.0**
Other gas facilities	Other reporting and recordkeeping	<$0.1	<$0.1
Proposed rule total[1]		**$739.7**	**$879.5**

[1] Total may not add up due to independent rounding.
[2] Distribution costs are presented as a range to reflect different assumptions regarding leak incidence and methane emissions rate across pipe materials. The low estimate is based on leak incidence and methane emission rates from Lamb *et al.* (2015), whereas the high estimate is based on rates from Weller *et al.* (2020).
Source: PHMSA analysis

Benefits

By reducing the leakage of gas from pipelines into the atmosphere, the proposed rule is expected to provide both private benefits (via avoided product loss) and societal benefits (via avoided emissions of methane and other gases). For this analysis, PHMSA focused its analysis on methane emissions from natural gas and liquefied natural gas pipeline facilities, and separately quantified the climate benefits and avoided natural gas losses. Climate benefits are developed using social cost estimates from the Interagency Working Group (IWG) on the Social Cost of Greenhouse Gases (SC-GHG), primarily the Social Cost of Methane (SC-CH4) estimates. Table ES-2 summarizes the methane emission reductions attributable to the proposed rule, whereas Table ES-3 summarizes the associated climate benefits and those derived from avoided natural gas losses.[2] PHMA estimates that methane emission reductions 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

[2] In the executive summary PHMSA primarily presents figures based on the IWG 3 percent discount rate scenario, but presents benefits associated with all IWG scenarios in Table ES-7 and more comprehensive detail for all IWG scenarios in section 5 of this report. PHMSA chose to focus on the 3 percent scenario to represent benefits and costs in the executive summary because it is the IWG scenario that uses a discount rate consistent with one of the rates in EO 12866 guidance, and in order to improve readability of the executive summary and keep it reasonably brief. As explained further in section 5.1.2, PHMSA has determined that all of the SC-CH4 estimates developed by the IWG are appropriate for use in estimating the climate benefits from methane emissions reductions expected to occur as a result of the proposed rule.

projected over the period of analysis based on the pipeline mileage, empirical emission factors, and existing survey and repair practices. See details of the modeling approach in section 2.1.5 and Appendix A.

Table ES-2: Total changes in methane emissions under the proposed rule (metric tons CH_4)						
Year	**Gathering**	**Transmission**	**Distribution[1]**		**Total emissions[2]**	
			Lamb *et al.* (2015)	**Weller *et al.* (2020)**	**Low**	**High**
2024	-52,300	-1,300	-42,280	-115,300	-95,900	-168,900
2025	-79,000	-1,900	-82,470	-229,900	-163,300	-310,800
2026	-106,000	-2,500	-135,400	-423,500	-243,800	-532,000
2027	-133,400	-3,100	-179,300	-588,400	-315,800	-724,900
2028	-161,300	-3,700	-206,400	-699,400	-371,300	-864,300
2029	-189,500	-4,300	-223,100	-770,700	-416,900	-964,500
2030	-218,100	-4,900	-237,500	-817,200	-460,500	-1,040,200
2031	-247,100	-5,600	-251,600	-863,800	-504,200	-1,116,400
2032	-276,500	-6,200	-265,300	-910,600	-547,900	-1,193,300
2033	-306,300	-6,800	-278,600	-957,600	-591,700	-1,270,800
2034	-336,500	-7,500	-291,500	-1,005,000	-635,500	-1,348,900
2035	-367,200	-8,100	-304,200	-1,052,000	-679,500	-1,427,700
2036	-398,300	-8,800	-316,700	-1,100,000	-723,800	-1,507,300
2037	-429,800	-9,500	-329,000	-1,148,000	-768,300	-1,587,600
2038	-461,800	-10,100	-341,200	-1,197,000	-813,100	-1,668,700

[1] Distribution emissions are presented as a range to reflect different assumptions regarding leak incidence and methane emissions rate across pipe materials.
[2] Total emissions reflect the range of estimated distribution emissions. 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).
Source: PHMSA analysis

Table ES-3: Annualized benefits from avoided methane emissions and natural gas loss (million 2020$, 3 percent discount rate)						
Benefit Category	**Gathering**	**Transmission**	**Distribution**		**Total benefits[1]**	
			Lamb *et al.* (2015)	**Weller *et al.* (2020)**	**Low**	**High**
Climate benefits (based on the Interagency Working Group (IWG) average at 3%)	$507	$11.1	$472	$1,607	$990	$2,126
Natural gas losses	$46	$1.0	$43	$147	$90	$194
Total monetized benefits	**$553**	**$12.1**	**$515**	**$1,754**	**$1,081**	**$2,320**
Additional benefits of reducing methane releases	Not monetized					
Benefits of reducing releases of other pollutants (*e.g.*, volatile organic compounds (VOCs) and hazardous air pollutants (HAPs))	Not monetized					
Safety benefits	Not monetized					

[1] 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).
Source: PHMSA analysis

Due to data limitations, PHMSA was unable to quantify the safety benefits from preventing leaks of natural gas and other flammable, toxic, or corrosive gases. PHMSA was also unable to quantify some of the other environmental and health benefits associated with preventing releases of natural gas, and other flammable, toxic or corrosive gases, but 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) and other impacts of gas releases. These data limitations are discussed in more detail in section 5.4 below. PHMSA was unable to estimate the benefits of avoiding losses of gases other than natural gas, but the omission of the additional benefits of preventing releases of other gases is not expected to materially affect the overall benefits since natural gas pipelines account for nearly all of the mileage of part 192-regulated gathering pipelines, transmission pipelines, and distribution mains (see sections 3.1.1 and 3.1.2).

Net Benefits

Table ES-4 compares the annualized costs and benefits of the proposed rule at 3 and 7 percent discount rates. At 3 percent the proposed rule is estimated to provide net benefits ranging from $341 million to $1,440 million per year. The net benefits range from $320 million to $1,404 million at 7 percent.

Table ES-4: Comparisons of the total annualized costs and benefits of the proposed rule (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
	Cost	$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 and benefits based on Lamb *et al.* (2015) whereas the high estimate reflects distribution costs and benefits 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 5.1.3 for estimated climate benefits using other discount rates.
Source: PHMSA analysis

Evaluation of the Effects of Uncertainty on Benefits and Costs of the Proposed Rule

Important sources of uncertainty in the analysis of the benefits and costs of the proposed rule are from the baseline practices implemented by pipeline operators, such as current leak detection methods, survey frequencies, timing of repairs, and others. Differences between these practices and the proposed rule requirements determine the incremental emissions reductions that would be achieved under the proposed rule. Other sources of uncertainty include leak incidence rates and emission factors, and how these values vary by pipeline type, age, and other characteristics.

Conducting a formal quantitative analysis to model how these sources of uncertainty affect the costs and benefits would require more detailed information than is currently available to PHMSA, such as data on the distribution of model parameters for regulated pipelines and operators, as well as the relationships between the model parameters (*e.g.*, effects of baseline survey practices on leak incidence rates). Due to the lack of such detailed data, PHMSA used point estimates for most model parameters to estimate the costs and benefits of the rule. However, to inform the understanding of how the costs and benefits may vary depending on the modeling assumptions, PHMSA conducted a sensitivity analysis, summarized below and detailed in section 6 of this PRIA, that considers a range of values for selected inputs. PHMSA seeks information that could enable a more detailed quantitative analysis of uncertainty for the final rule.

For distribution pipelines, PHMSA considered uncertainty around the leak incidence rates and emission factors by incorporating two different sets of assumptions based on the literature, resulting in low and high estimates. PHMSA performed sensitivity analyses for selected other parameters, as detailed in section 6. Table ES-5 summarizes PHMSA's evaluation of the impacts of selected key parameters on the estimated benefits and costs of the proposed rule. Specifically, PHMSA varied gathering leak emission rates for the subset of gathering lines in Texas and New Mexico to use alternative values reported in the literature based on surveys conducted in the Permian Basin; these alternative rates are more than 100 times larger than the rates PHMSA used for the main analysis and for gathering lines in other states. PHMSA also varied survey effectiveness to use a 50 percent difference between advanced leak survey and more traditional methods, as compared to the 15 percent used for the main analysis.

Table ES-5: Sensitivity of costs and benefits to varying selected assumptions and parameter values (million 2020$, at 3 percent discount)

Scenario / sensitivity parameter	Annualized costs		Annualized benefits[1]		Net benefits	
	Low[2]	High[2]	Low[2]	High[2]	Low[2]	High[2]
Main analysis	**$740**	**$880**	**$1,081**	**$2,320**	**$341**	**$1,440**
Gathering leak emission rates in Permian Basin	$738	$878	$30,244	$31,484	$29,506	$30,606
Change in survey effectiveness	$847	$1,106	$1,829	$3,675	$982	$2,569

[1] Climate benefits based on estimate developed by the IWG of the average SC-CH_4 at 3 percent discount.
[2] Range of distribution costs and benefits based on assumptions regarding leak incidence and methane emissions rate across pipe materials. The low estimate is based on leak incidence and methane emission rates from Lamb *et al.* (2015), whereas the high estimate is based on rates from Weller *et al.* (2020).
Source: PHMSA analysis

The proposed rule incorporates several self-implementing provisions under Section 114 of the PIPES Act of 2020 that mandate changes to inspection and maintenance plans to eliminate hazardous leaks of all gases and minimize releases of natural gas from pipeline facilities. The plans must also address the remediation or replacement of pipelines known to leak based on their material, design, or past maintenance and operating history. The plans must specifically address intentional venting during blowdown or other scheduled maintenance activities. Because these changes are mandated explicitly by the Act and are already in effect, they are included in the baseline (see section 2.1.4) and PHMSA did not attribute the associated costs or benefits to the proposed rule. There is uncertainty, however, regarding the specific measures operators are including in their plans to address the Section 114 requirements in the absence of the clarifications included in this proposed rule. PHMSA also evaluated the proposed rule relative to a pre-statutory baseline, in part to address this uncertainty. Table ES-6 presents the results of this analysis. PHMSA further addressed this uncertainty in the analysis detailed in section 6.1 which provides the estimated costs and benefits of blowdown mitigation requirements. This uncertainty analysis provides insight into the potential full economic impacts of the statutory changes made by Section 114 and this regulatory action.

Table ES-6: Total annualized costs and benefits of the proposed rule relative to a pre-statutory baseline (million 2020$, at 3 percent discount)						
Rule element	Annualized costs		Annualized benefits[1]		Net benefits	
	Low[2]	High[2]	Low[2]	High[2]	Low[2]	High[2]
Blowdown emissions		$657		$229		-$429
Other requirements	$739	$878	$1,061	$2,301	$324	$1,423
Proposed rule total	**$1,396**	**$1,535**	**$1,290**	**$2,530**	**-$105**	**$995**

[1] Climate benefits based on estimate developed by the IWG of the average SC-CH_4 at 3 percent discount.
[2] The range reflects different leak incidence rates and emission factors for distribution pipelines. For the low estimate, distribution costs and benefits are based on distribution leak incidence rates and emission factors from Lamb *et al.* (2015). For the high estimate, distribution costs and benefits are based on distribution leak incidence rates and emission factors from Weller *et al.* (2020).
Source: PHMSA analysis

The bulk of the quantified benefits of the proposed rule would result from avoiding methane emissions, which are monetized using estimates of the social cost of methane (SC-CH_4) developed by the Interagency Working Group on the Social Cost of Greenhouse Gases (2021). Because greenhouse gases are long-lived and subsequent damages of current emissions can occur over a long time, the approach to discounting greatly influences the present value of future damages. Table ES-7 presents the results of the analysis.

Table ES-7: Annualized benefits of avoided methane emissions across the range of SC-CH_4 value (million 2020$, discounted and annualized at indicated discount rate)						
Basis for SC-CH_4 value (discount rate)	Gathering	Transmission	Distribution		Total	
			Lamb *et al.* (2015)	Weller *et al.* (2020)	Low[1]	High[1]
5% average[2]	$229	$5	$215	$731	$449	$965
3% average[2]	$507	$11	$472	$1,607	$990	$2,126
2.5% average[2]	$640	$14	$593	$2,023	$1,248	$2,678
3% 95th percentile[2]	$1,323	$29	$1,227	$4,182	$2,579	$5,534

[1] 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] Based on SC-CH_4 values in Interagency Working Group on Social Cost of Greenhouse Gases (2021). See Table 34.
.
Source: PHMSA analysis

Benefits and Costs of Regulatory Alternatives

PHMSA estimated the benefits and costs of regulatory alternatives to the proposed rule. Two of these alternatives focus primarily on the distribution sector and include: (1) leaving survey intervals for plastic pipes outside of business districts unchanged (5 years), and (2) requiring annual surveys for all distribution mains. Table ES-8 compares the costs and benefits of these alternatives and those of the proposed rule. See section 6.5.1 for details.

Table ES-8: Annualized costs and benefits of alternative distribution leak survey requirements (million 2020$)							
Discount rate and analyzed LDAR requirements		Annualized costs		Annualized benefits		Net benefits[1]	
		Lamb *et al.* (2015)	Weller *et al.* (2020)	Lamb *et al.* (2015)	Weller *et al.* (2020)	Lamb *et al.* (2015)	Weller *et al.* (2020)
3%	**Proposed rule**	**$740**	**$880**	**$1,081**	**$2,320**	**$340**	**$1,440**

Table ES-8: Annualized costs and benefits of alternative distribution leak survey requirements (million 2020$)							
Discount rate and analyzed LDAR requirements		Annualized costs		Annualized benefits		Net benefits[1]	
		Lamb *et al.* (2015)	Weller *et al.* (2020)	Lamb *et al.* (2015)	Weller *et al.* (2020)	Lamb *et al.* (2015)	Weller *et al.* (2020)
	Alternative 2 – 5-year interval for plastic mains	$564	$624	$1,071	$1,864	$507	$1,240
	Alternative 3 – Annual leak surveys	$2,056	$2,634	$1,251	$4,779	-$805	$2,145
7%[2]	**Proposed rule**	**$753**	**$900**	**$1,073**	**$2,304**	**$320**	**$1,404**
	Alternative 2 – 5-year interval for plastic mains	$578	$639	$1,063	$1,850	$485	$1,211
	Alternative 3 – Annual leak surveys	$2,065	$2,679	$1,243	$4,749	-$822	$2,070

[1] Negative values represent net costs whereas positive values represent net benefits.
[2] Costs and benefits from avoided natural gas losses (included in total benefits) are discounted at 7 percent, whereas climate benefits (also included in the total benefits) are discounted at 3 percent. See section 5.1.3 for estimated climate benefits using other discount rates.
Source: PHMSA analysis

Another alternative would require monitoring and reduction of fugitive methane emissions from gas transmission compressor stations and gas gathering and boosting compressor stations. The proposed rule exempts these sources 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), advanced leak detection program (ALDP) (§192.763) and qualification of leak detection personnel (§ 192.769), based on the expectation that EPA's requirements at 40 CFR part 60 provide public safety and environmental protection comparable to PHMSA's proposal.[3]

As of the date of this analysis, the EPA requirements have been proposed but not finalized. In the event EPA does not finalize the proposed requirements, PHMSA could proceed with setting equivalent requirements for gas transmission compressor stations and gathering and boosting (G&B) stations by eliminating the exemption. Table ES-9 provide the additional costs and benefits that could result from this alternative. See section 6.5.2 for details.

Table ES-9: Summary of additional costs and benefits of monitoring and repair requirements for G&B and transmission compressor stations (Alternative 4; Million 2020$, annualized at 3 percent discount)			
Item	G&B	Transmission	Total
Annualized costs	$47.2	$11.9	$59.2
Annualized benefits	$84.3	$34.8	$119.0
Net benefits	$37.1	$22.8	$59.9

Impacts on Small Businesses and on Energy Supply, Distribution, or Use

PHMSA prepared an Initial Regulatory Flexibility Act (IRFA) analysis of the proposed rule. PHMSA estimates that 1,815 small entities owned gas gathering, gas transmission, or gas

[3] EPA's current and proposed Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources in the Oil and Natural Gas Sector (49 CFR part 60, subparts OOOOa, OOOOb [NSPS] and OOOOc [EG]) apply to compressor stations on gas transmission pipelines and gas gathering pipelines, among other sources.

distribution systems in 2020, with some entities owning both gas gathering and transmission and gas distribution systems. A simple screening analysis shows that for 51 percent to 65 percent of small entities, the after-tax direct compliance costs are estimated to be 1 percent or greater of annual revenue; and for 21 percent to 35 percent of small entities, the costs are 3 percent or greater than the revenue. For additional information, see section 6.

PHMSA assessed the potential for the proposed rule to increase the cost of natural gas distributed to end consumers. The annualized costs of the proposed rule ($740 million to $880 million at a 3 percent discount rate and $753 million to $900 million at a 7 percent discount rate) translate into $0.03 per thousand cubic feet of natural gas. Assuming that these costs are passed through to all consumer types uniformly, they would represent approximately a 0.3 percent increase over the national average price of gas delivered to residential consumers and is equivalent to an increase of $2.10 to $2.56 per year for the average residential customer. These small consumer price increases indicate that the proposed rule is unlikely to have a significant adverse effect on energy supply, distribution, or use at a national or regional level. For additional information, see section 8.2.

PHMSA analyzed the distribution of costs across the different types of entities that own and operate pipeline systems to provide insight on the potential compliance burden to government entities (*i.e.*, State and local governments) that own or operate pipeline systems, and to small government entities specifically, as well as privately-owned entities. PHMSA identified 1,008 government entities that operate a total of 1,077 pipeline systems. Of these entities, 959 are small governments. At a 7 percent discount rate, the total costs to government entities range between $67 million and $96 million, depending on the assumed distribution main leak incidence rate, whereas the total costs to private entities (including cooperatives) range between $685 million and $803 million. The annual compliance costs tend to be smaller, on average, for governments than for private entities and also tend to be smaller for small governments than for large governments, because government owned systems tend to be smaller, making costs per entity smaller. For additional information, see section 8.5.

1 Determination of Need and Summary of Proposed Rule

1.1 Determination of Need

Federal leak detection and repair standards for gas pipelines have remained largely unchanged since the 1970s. Since that time, advances in leak detection technology and the growing understanding of the contribution of methane—the primary component of natural gas and a powerful greenhouse gas—to climate change, as well as recent incidents attributable to inadequate leak survey practices, have pointed to the need to update those standards. The general leak repair requirements in §192.703(c) and distribution line leakage survey requirements in §192.723 were established on August 19, 1970 (35 FR 13257), and leakage survey requirements for gas transmission lines were promulgated five years later, on May 9, 1975 (40 FR 20279). These provisions lack sufficiently robust and enforceable standards for the performance of leakage surveys and repair of leaks discovered, especially for leaks that pipeline operators consider "non-hazardous" to safety based on the leak rate, location, and other factors.

This proposed rulemaking addresses a negative externality in gas transportation wherein the cost of emissions of methane and other gases associated with leaks from gas pipeline facilities are borne not by pipeline operators responsible for detecting and repairing leaks, but by society as a whole. Gas pipeline and other facility contributions to methane emissions have been well documented. For example, the U.S. Environmental Protection Agency (EPA) estimates that gas sources regulated by PHMSA emitted approximately 0.9 million metric tons (MMTon) of methane in 2020, based on the Greenhouse Gas Inventory (EPA, 2022a; EPA, 2022e). Market forces alone have proven insufficient to fully incentivize distribution pipeline operators to detect and repair natural gas leaks. Studies have found underinvestment in cost-effective methane reduction strategies relative to the cost of the lost gas—*i.e.*, leak mitigation measures whose cost is below the value of the gas that would be contained by executing them are not being implemented—particularly when also considering the social cost of methane (Hausman & Muehlenbachs, 2018; Hausman & Raimi, 2019). In part, this is because cost-of-service regulations often incorporate allowances for "just and reasonable" amount of lost and unaccounted for (LAUF) gas, with that cost passed through to customers. Although some states have adopted regulatory incentives to reduce LAUF gas, such losses are still considered part of "normal" operations and factored into operating costs. While some States have adopted such regulatory incentives, many have not, and it is not clear when or if they may take action on this issue. Further, the economic incentives for operators that bear the cost of lost gas are to reduce leaks only to the point where the marginal cost of leak detection and mitigation equals the value of lost gas. Further, even if companies were incentivized to avoid losses through higher operating costs and lower net revenue, they would not internalize the external costs of climate change impacts of methane emissions, which are roughly 10 times greater than natural gas market prices.[4] Thus, curtailing methane emissions as needed from a societal perspective is not achievable through the existing market mechanisms alone. The proposed rule does not change those market mechanisms or incentives. Instead, the rule addresses the negative externality by requiring operators to perform leak surveys and repair leaks.

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[4] Based on projected Henry Hub spot prices from the Energy Information Administration's Annual Energy Outlook 2021 (U.S. Energy Information Administration, 2021).

Natural gas production is projected to increase by 24 percent between 2021 and 2050, according to the Energy Information Administration (EIA, 2022a). Exports, particularly liquefied natural gas (LNG), are projected to account for much of the growth in production, due to strong global demand and the continued expansion of LNG export capacity. Since methane emissions are in part driven by natural gas throughput (Cooper *et al.*, 2021), putting in place measures to ensure that leaks are found and promptly fixed will be critical for meeting future energy needs in an environmentally responsible manner. In Section 113 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020; Pub. L. 116-260), Congress recognized these weaknesses and the need for more stringent regulation by mandating that PHMSA establish performance standards for leak detection and repair programs and require that gas pipeline operators implement such programs.

The Notice of Proposed Rule Making (NPRM) published in the Federal Register (FR) provides additional information on the policy background and need for this rulemaking, as well as a section-by-section discussion of the rule provisions.

1.2 Summary of Proposed Rule

1.2.1 Proposed Changes to Leak Detection and Repair Requirements Applicable to Regulated Gas Pipelines and Other Gas Facilities

PHMSA proposes to establish performance standards for advanced leak detection programs, grading and repair standards for gas pipeline leaks, enhanced leakage survey and repair requirements, and other requirements designed to minimize emissions of methane and other flammable, toxic, and corrosive gases from gas pipeline systems. The proposed rule requirements would apply to all regulated gas gathering, gas transmission, gas distribution pipelines and other gas pipeline facilities, offshore or onshore, that transport natural gas or other gas commodities subject to 49 CFR part 192.

In addition, PHMSA is proposing changes to memorialize in PHMSA regulations the self-implementing provisions of the PIPES Act of 2020 by requiring operators to mitigate vented and other emissions from gas pipeline facilities (including part 192-regulated gathering, transmission, distribution, underground storage, and part 193-regulated LNG facilities) (§§192.9, 192.12, 192.605, 192.770, 193.2503, 193.2523 and 193.2605).

Table 1 summarizes the proposed rule changes. The table focuses on those rule elements that PHMSA assessed as having the potential[5] to result in incremental costs to pipeline operators or yield social costs or benefits. The table first summarizes general requirements applicable to all regulated pipelines, including LNG facilities and underground natural gas storage facilities (UNGSFs),[6] such as performance criteria for advanced leak detection (ALD) systems used to

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5 PHMSA has estimated no incremental costs for some elements after further analysis.

6 The Pipeline Safety Regulations define an LNG facility as a "pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas." (§193.2007). The Pipeline Safety Regulations define an underground natural gas storage facility (UNGSF) as "a gas pipeline

conduct leak surveys. The table then highlights the proposed changes to the requirements specific to gas gathering and gas transmission pipelines, gas distribution lines, LNG facilities, and UNGSFs. Finally, for each topic, the table provides in the right-most column the PRIA section(s) detailing the analysis of incremental costs. Note that the table provides only a high-level summary of the changes. For additional details, including the actual text of the proposed changes, refer to the NPRM.

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facility that stores natural gas underground incidental to the transportation of natural gas, including (1) (i) A depleted hydrocarbon reservoir; (ii) An aquifer reservoir; or (iii) A solution-mined salt cavern. (2) In addition to the reservoir or cavern, a 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." (§192.3)

Table 1: Summary of principal changes proposed to the leak detection and repair requirements for gas pipelines			
Industry Segment	**Topic**	**Changes**	**PRIA Section(s)**
General	191.19: Large-volume release reports and 191.23: Reporting safety-related conditions	• Adds a requirement to report large-volume releases, defined as releases greater than 1 million cubic foot (MMcf), to PHMSA. (Note that this requirement applies to releases from pipelines as well as other gas facilities, including LNG facilities and UNGSFs.) • Excepts large-volume releases as defined in proposed §191.3 from the requirement to submit a safety-related condition report pursuant to §191.23, thereby leaving reportable safety-related conditions unchanged. • Amends §191.23(a)(9) to explicitly limit that safety-related condition reporting requirement to imminent hazards to public safety.	Regulated gathering and transmission: section 4.1.5 Distribution: section 4.2.3 Other gas facilities: section 4.3.1
	192.553 and 192.557: Uprating	• Revises 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. • Revises the uprating requirements to clarify that any leaks detected must be repaired prior to uprating a pipeline that will operate at a Maximum Allowable Operating Pressure (MAOP) producing a hoop stress less than 30 percent of Specified Minimum Yield Strength (SMYS), or that is made of plastic, cast iron, or ductile iron.	Regulated gathering and transmission: section 4.1.5 Distribution: section 4.2.3
	192.760: Leak grading and repair (also 192.703(c)-(d), 192.709, and 192.763)	• Requires operators to develop procedures for grading and repairing leaks (192.760(a)). • Defines criteria for grading leaks from gathering, transmission, and distribution pipes into grades 1, 2, and 3. Grade 1 leaks are existing or probable hazards to persons or property, or existing hazards to the environment. Grade 2 leaks represent a probable future hazard to safety or the environment, but not current or imminent hazards like grade 1 leaks. Grade 3 leaks do not meet the grades 1 or 2 criteria. (192.760(b) and (c)) • Specifies deadlines for repairing leaks of each grade (192.760(b) and (c)). • Requires post-repair evaluation (192.760(e)). • Requires operators to submit requests for extensions to the deadline for repairing grade 3 leaks on a case-by-case basis (192.760(h)). • Requires documentation of the leaks, repairs, and post-repair evaluation (192.760(i)).	Regulated gathering and transmission: section 4.1.5 (post-repair evaluation covered in section 4.1.3) Distribution: section 4.2.3 (post-repair evaluation covered in section 4.2.2)

Table 1: Summary of principal changes proposed to the leak detection and repair requirements for gas pipelines			
Industry Segment	**Topic**	**Changes**	**PRIA Section(s)**
	192.763: Advanced leak detection systems	• Specifies the ALD performance standards for detection equipment and methods, including minimum sensitivity. • Outline elements of the ALD program, including equipment, procedures, frequency of leakage surveys, and evaluation and improvement. • Specifies requirements for operators to request alternative performance standards for certain gathering and transmission lines. • Requires that operators conduct an analysis to select the tools, procedures, and analysis methodology appropriate to their conditions.	Regulated gathering and transmission: section 4.1.5 Distribution: section 4.2.3
	192.769: Leakage survey practices	• Requires that leakage survey, analysis, and grading be conducted only by adequately qualified individuals.	Regulated gathering and transmission: section 4.1.5 Distribution: section 4.2.3
	192.773: Pressure relief device maintenance and adjustment of configuration	• Requires operators to have written operation and maintenance (O&M) procedures for assessment of the proper function of pressure relief devices. • Requires operators to assess and either repair or replace malfunctioning pressure relief devices. • Identifies specific action operators have to take on operation of a malfunctioning pressure relief device. • Requires that operators maintain records documenting the proper operation and any remediation/replacement of pressure relief devices for the service life of their facilities.	Regulated gathering and transmission: section 4.1.5 Distribution: section 4.2.3
Gathering and transmission	191.17: Annual reports	• Changes the gas transmission and regulated gathering annual report form (Form F7100.2-1) to collect data on leaks detected and repaired by grade during the annual reporting period.	Section 4.1.5
	191.29: National Pipeline Mapping System (NPMS)	• Adds NPMS reporting requirements for regulated gas gathering lines (Type A, Type B, and Type C), onshore or offshore, by deleting the current exemption for these systems.	Section 4.1.4
	192.9: Requirements applicable to gathering lines	• Revises the list of requirements applicable to Type B and Type C gathering lines and to offshore gas gathering pipelines. In particular, the revisions expand the scope of leak survey and repair requirements to all Type C gathering pipelines.	*Addressed as individual provisions.*
	192.199: Design and configuration of pressure relief and limiting valves	• Requires that all new, replaced, relocated, or otherwise changed overpressure protection devices be designed and configured to minimize unnecessary releases of gas to the atmosphere.	Sections 6.1.1 and 6.1.2
	192.605: Procedural manual for operations, maintenance, and emergencies	• Extend the requirements for procedural manuals to Type B and Type C gathering lines.	Section 4.1.5
	192.615: Emergency plans	• Extends the requirements for emergency plans to Type B gathering lines.	Section 4.1.5

Table 1: Summary of principal changes proposed to the leak detection and repair requirements for gas pipelines			
Industry Segment	**Topic**	**Changes**	**PRIA Section(s)**
	192.705: Patrolling	• Increases the minimum frequency of visual right-of-way patrols on gas transmission lines and on part 192-regulated Type A gas gathering pipelines to 12 times per calendar year, with the interval not exceeding 45 days between patrols. • Requires patrol for Type B and Type C gathering lines at frequencies identical to the patrol requirements for as transmission and Type A gathering pipelines.	Section 4.1.1
	192.706: Leakage surveys	• Revises the survey frequencies for different lines according to pipeline type (gathering, transmission), location (within/outside of high consequence area (HCA) and by class location), odorization, leak or accident history, and type of equipment. • Shortens the minimum frequency for leakage surveys in HCA pipelines. • Requires more frequent surveys for all valves, flanges, tie-ins with valves and flanges, in-line inspection (ILI) launcher and receiver facilities, and pipe with a known leak or incident history. • Requires that leak detection surveys be conducted with equipment meeting ALD performance standards in 192.763. • Allows for an exemption from the equipment requirements if operators obtain authorization from PHMSA.	Section 4.1.2
	192.770: Minimizing emissions from blowdowns	• Requires that operator implement practices that minimize the amount of gas released to the atmosphere during blowdown, and O&M procedures to verify the proper functioning of equipment that may release gas.	Sections 6.1.1 and 6.1.2
Distribution	191.11: Distribution annual reports	• Changes Form F7100.1-1 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. • Changes the form to include estimated aggregate gas emissions from leaks by grade and other emissions categorized by source category over the annual reporting period.	Section 4.2.3
	192.605: Procedural manual for operations, maintenance, and emergencies	• Incorporates the self-executing mandate at section 114 of the PIPES Act of 2020 that the maintenance and operating procedures 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.	Sections 6.1.1 and 6.1.2
	192.723: Leakage surveys	• Revises the survey frequencies for different lines according to location (inside or outside business districts), pipe material and corrosion protection, and leak or accident history. • Increases the frequency of leakage surveys outside business districts. • Adds requirements to conduct leakage surveys when freezing or other environmental conditions may allow gas migration into nearby buildings, or after extreme weather events or land movement. • Requires that leak detection surveys be conducted with equipment meeting ALD performance standards in § 192.763.	Section 4.2.1

Table 1: Summary of principal changes proposed to the leak detection and repair requirements for gas pipelines			
Industry Segment	**Topic**	**Changes**	**PRIA Section(s)**
LNG facilities	193.2503: Operating procedures and 193.2605: Maintenance procedures	• Incorporates the self-implementing mandate that requires operators update their procedures to provide for the elimination of leaks and minimize release of gas from pipeline facilities by requiring LNG facilities to have and follow written procedures for normal and abnormal operations and for maintenance.	Section 4.3
	193.2523: Minimizing emissions from blowdowns and boiloff	• Requires LNG facilities to mitigate methane emissions from non-emergency, vented releases such as blowdowns and tank boiloff.	Sections 6.1.1 and 6.1.2
	193.2624 Leakage Surveys	• Requires operators of LNG facilities 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 4 ½ months. • Specifies minimum performance standards for leak detection equipment.	*Costs not quantified*
UNGSFs	191.12(c): Procedural manual	• Requires UNGSFs to update their procedures to provide for the elimination of leaks and minimize release of natural gas from pipeline facilities.	Sections 6.1.1 and 6.1.2

1.2.2 Other Proposed Rule Changes

Certain additional proposed rule changes define terms, clarify existing requirements and practices, or revise text to ensure consistency across sections and therefore are not anticipated to result in incremental costs (or benefits). These additional rule changes, which are not detailed in this report, include:

- **Section 191.3: Definitions.** PHMSA proposes to define, for the purposes of all subparts of part 192 other than integrity management (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 expects any compliance burdens associated with this proposed revision expanding the "hazard" concept in connection with leaks would be *de minimis* because (1) a reasonably prudent operator would already employ practices and procedures sensitive to environmental harms from leaks in their activities, and (2) the mechanism for pertinent public safety and environmental harms (*i.e.*, the release of gas from a pipeline from a leak) is identical.
- **Section 191.23: Reporting safety-related conditions.** PHMSA proposes an exception for large-volume releases as defined in proposed §191.3 from the requirement to submit a safety-related condition report pursuant to §191.23, thereby leaving reportable safety-related conditions unchanged.
- **Sections 192.507, 192.509, and 192.513: Test requirements**. PHMSA proposes to amend the qualifier "potentially" modifying "hazardous leak" in recognition of the certainty of environmental harms from any released gas.
- **Section 192.617: Investigation of failures**. PHMSA proposes to define the term "failure" for the purposes of existing requirements to investigate the causes of failures and incidents. This change would clarify that these requirements apply to leaks and is consistent with existing industry standards and with PHMSA's core hazardous materials safety mission.
- **Section 192.629: Purging of pipelines**. PHMSA proposes to clarify that the provisions governing the purging of gas from each of gas transmission, distribution, offshore gathering and Type A gathering pipelines remain focused on addressing risks to public safety, thereby leaving purging provisions unchanged.
- **Section 192.769: Qualification of leakage survey, investigation, and grading personnel.** PHMSA proposes to clarify training and qualification requirements for personnel that conduct leakage surveys, investigation, and leak grading on gas transmission, distribution, offshore gathering, and Type A gathering pipelines. Specifically, §192.769 clarifies that surveying, investigating, and grading leaks are covered tasks under subpart N and therefore personnel conducting these activities must be qualified and have documented work history or training.

2 Analysis Framework and Alternatives Considered

The analyses of costs, benefits and economic impacts in this report fulfill the requirements under various executive orders and statutes. For example, Executive Orders 12866, "Regulatory Planning and Review," and 13563, "Improving Regulation and Regulatory Review," require agencies to regulate in the "most cost-effective manner," to make a "reasoned determination that the benefits of the intended regulation justify its costs," and to develop regulations that "impose the least burden on society." Section 8 of this PRIA provides additional details on analyses that fulfill the requirements of applicable statutes and executive orders.

2.1 Analysis Framework and Conventions

2.1.1 Timeframe for Analysis

PHMSA uses a 15-year period for the analysis of the costs and benefits of the proposed rule, starting with the expected rule promulgation in 2024 and ending in 2038. PHMSA chose this analysis period to capture several full leak survey cycles given the maximum intervals between consecutive surveys on different types of gas gathering and gas transmission pipelines (no more than 1 year in the baseline) or gas distribution mains (1, 3, or 5 years in the baseline).

2.1.2 Discounting of Future Costs and Benefits

PHMSA assumes promulgation of the final rule in 2024 and discounts the estimated costs and benefits to that year, assuming that costs are incurred at the start of each analysis year (*i.e.*, costs incurred in 2024 are undiscounted, costs incurred in 2025 are discounted by one year, etc.). The analytic framework includes two other basic temporal components, which are used consistently throughout the analysis of social benefits and social costs:

- **Constant dollars**. All future costs and benefits are expressed in constant 2020 dollars. Some monetary values of benefits and costs are based on historical market prices, and in those instances, PHMSA updated the prices to 2020 by applying appropriate price indexes based on the type of cost (*i.e.*, labor, construction, or a variety of goods and services).
- **Discount rate**. This analysis estimates the annualized value of future costs and benefits using two discount rates: 3 percent and 7 percent. This is consistent with guidance provided by the Office of Management and Budget (OMB) in Circular A-4, which recommends that 3 percent be used when a regulation affects private consumption and 7 percent be used in evaluating a regulation that will mainly displace or alter the use of capital in the private sector (U.S. OMB, 2003; updated 2009). One exception to this practice is discounting of the benefits of avoided methane emissions for which PHMSA uses values of the social cost of methane developed using discount rates of 2.5 percent, 3 percent, 5 percent and the 95th percentile, 3 percent. See sections 5.1.2 and 5.1.3 for details.

2.1.3 Sign Convention for Presenting Costs and Benefits

In presenting values of the costs and benefits of the proposed rule in this document, PHMSA uses the following conventions with respect to the signs of monetary values:

- Costs are presented as positive values when they represent additional costs to the operators or to society (cost savings are shown as negative values).
- Benefits are presented as positive values when they result in social welfare gains (*i.e.*, emission reductions) relative to the baseline. Note that negative emissions changes represent emission reductions from the baseline to the proposed rule and result in positive benefits.
- Net total values are calculated as benefits minus costs and are therefore presented as positive when benefits are larger, and negative when costs are larger.

2.1.4 Analysis Baseline

PHMSA examined the effects of the proposed rule against a baseline that reflects ongoing trends in the gas pipeline infrastructure, including leak detection, repair, and operation and maintenance (O&M) practices that gas pipeline operators are currently implementing to comply with applicable Federal and state regulations. The baseline is designed to reflect conditions in the absence of this regulatory action by PHMSA. Accordingly, the baseline reflects practices operators must implement to comply with the self-implementing provisions at Section 114 of the PIPES Act of 2020 since these provisions would apply in the absence of any additional regulatory action by PHMSA.

In the proposed rule, PHMSA adds detail to the broad requirements contained in Section 114 of the PIPES Act of 2020 to enhance clarity for operators and to ensure consistency with other regulatory requirements. While the effects of these clarifications are expected to be small, there may still be some incremental costs and benefits, depending on the measures operators would otherwise be implementing to meet the PIPES Act of 2020 statutory mandate. To inform understanding of the effects of the proposed rule, PHMSA also analyzed the costs and benefits of the proposed rule relative to a pre-statutory baseline. The differences between the two analysis baselines are the costs and benefits of the self-implementing provisions, which are covered separately in section 6.1 of this PRIA.

2.1.5 Modeling of Pipeline Leaks, Operator Actions, and Resulting Changes in Emissions

A core element of the analysis of costs and benefits of the proposed rule is the number of pipeline leaks existing, discovered, and repaired. PHMSA modeled the incidence of leaks on different types of pipelines based on empirical data, literature values, or other information. For each model scenario, year in the analysis period, industry segment, operator, and pipeline type, PHMSA estimated the following quantities:

1. pipeline mileage (including changes over time, based on historical trends);
2. number of detectable leaks, which depends on pipeline characteristics;
3. methane emissions, which depend on the pipeline type, number of existing leaks, and leak grade;
4. pipeline mileage surveyed, which depends on the interval between subsequent surveys;
5. number of leaks detected through the surveys, which depends on the effectiveness of the survey method; and

6. numbers of leaks repaired during the year, monitored during the year, and scheduled for repairs in a future year, which depend on the inventory of known leaks, leak grade, and repair deadline.

The first modeling element characterizes the universe of pipelines, including the distribution of pipelines by type, class location, etc. These characteristics do not change as a result of the rule and are therefore held the same between the baseline and regulatory scenarios. The next two modeling elements characterize the incidence of leaks and resulting methane emissions. The analysis treats leak incidence and methane emissions as a function of the pipeline type and uses the same emission factor for both the baseline and regulatory scenario, *i.e.*, PHMSA assumed that surveys and repairs do not materially affect the potential for a leak to form or the characteristics of that leak. The remaining three modeling elements are tied to survey frequencies and methods or repair practices, and modeling assumptions (*e.g.*, interval between subsequent leak surveys, survey effectiveness, leak repair deadline) for different pipeline types may therefore vary between the baseline and regulatory scenarios. The modeled occurrence of various activities (patrols, surveys, repairs, etc.) and the method employed by operators determine the estimated costs, whereas the number and types of leaks detected and repaired determine the estimated benefits.

Appendix A provides additional details on the modeling framework and parameter values for the baseline and regulatory scenarios.

2.2 Alternatives Considered

Executive Order 12866 instructs Federal agencies to provide an "assessment…of costs and benefits of potentially effective and reasonably feasible alternatives to the planned regulation" and "an explanation why the planned regulatory action is preferable to the identified potential alternatives."

See the NPRM and section 1.2 for a detailed description of the proposed rule. The alternatives PHMSA considered for this action are discussed below. Section 6.5 of this PRIA summarize the estimated costs and benefits of alternatives 2 and 3.

2.2.1 Alternative 1 No Action

PHMSA assessed keeping the requirements in 49 CFR unchanged. This alternative, however, would fail to fulfill the mandate Congress placed on PHMSA in Section 113 of the PIPES Act of 2020. The analysis of the proposed rule uses this alternative as the main baseline against which PHMSA estimates incremental costs and benefits of the proposed rule and of alternatives 2 and 3.[7] Section 3 describes this baseline, including estimated methane emissions.

[7] As discussed in section 2.1.4, PHMSA also analyzed the proposed rule relative to a pre-statutory baseline that also includes the costs and benefits of self-implementing provisions in Section 114 of the PIPES Act of 2020.

2.2.2 Alternative 2 Adjusted Leak Detection Survey Intervals for Plastic Distribution Mains

PHMSA assessed an alternative that would leave survey intervals for plastic pipes outside of business districts unchanged (5 years). PHMSA considered this alternative based on the differences in leak incidence for plastic pipes across studies (refer to discussion in section 3.2.3) and the associated uncertainty on whether more frequent surveys of relatively new plastic pipes will provide the benefits estimated for the proposed rule. As summarized in section 6.5 of this PRIA, this alternative has lower costs, but also much lower benefits than the proposed rule, relative to the baseline. Based on studies that show plastic pipes as representing significant sources of methane leaks, PHMSA is not proposing this alternative.

2.2.3 Alternative 3 Annual Surveys of All Distribution Mains

PHMSA also assessed an alternative that would require annual surveys for all distribution mains. While this alternative goes the furthest in fulfilling the PIPES Act of 2020 mandate, it results in much larger incremental costs for operators relative to the baseline, as summarized in section 6.5 of this PRIA. PHMSA did not propose this alternative.

2.2.4 Alternative 4 Leak Detection and Repair Requirements at Gas Transmission Pipeline Compressor Stations and Gas Gathering Pipeline Boosting Stations

EPA's current and proposed Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources in the Oil and Natural Gas Sector (49 CFR part 60, subparts OOOOa, OOOOb [NSPS] and OOOOc [EG]) apply to compressor stations on gas transmission pipelines and gas gathering pipelines, among other sources. The regulations set requirements for methane emissions monitoring, repair, and maintenance of certain pipeline facilities and their appurtenances.

Given EPA requirements, PHMSA is proposing to exempt gas transmission and gas gathering compressor stations subject to methane emissions standards (at current 40 CFR part 60, subpart OOOOa regulations, proposed subpart OOOOb updates and proposed 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), as well as any subsequent methane emissions standards at 40 CFR part 60) 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), advanced leak detection program (ALDP) (§192.763) and qualification of leak detection personnel (§192.769). In proposing these exemptions, PHMSA considered that EPA's regime at 40 CFR part 60 for monitoring fugitive methane emissions from gas transmission compression stations and gas gathering and boosting (G&B) compressor stations provides public safety and environmental protection comparable to PHMSA's proposal. Although PHMSA assessed an alternative where no such exemption would be provided, PHMSA did not propose that alternative to avoid duplicative regulation of those facilities.

3 Baseline Conditions

As described in section 2.1.4, PHMSA examined the benefits and costs of the proposed rule against a baseline that reflects ongoing trends in the gas pipeline infrastructure, including leak detection, repair, and O&M practices that gas pipeline operators are currently implementing to comply with applicable federal and state regulations. The baseline also reflects practices operators must implement to comply with the self-implementing provisions at Section 114 of the PIPES Act of 2020.

3.1 Regulated Entities

The proposed rule contains requirements applicable to all regulated gas gathering, gas transmission and gas distribution pipelines, offshore or onshore, and transporting natural gas or other gas commodities. Some proposed requirements also apply to other components of the natural gas system, such as LNG facilities and UNGSFs. The sections below describe the gas pipelines, operators, and other gas facilities subject to the proposed rule requirements.

3.1.1 Gas Gathering and Gas Transmission

The proposed rule requirements apply to all regulated gas gathering and gas transmission pipelines, offshore or onshore, and transporting natural gas or other gas commodities.

Table 2 summarizes the reported mileage of gas gathering and gas transmission pipelines by class location for calendar years 2015 through 2020, the most recent six years of data available at the time PHMSA conducted its analysis. The pipeline safety regulations at 49 CFR 192.5 use class locations for onshore pipelines to provide a graded approach to ensuring safety margins and standards commensurate with the potential consequences of pipeline incidents and are based on the population density near a pipeline. During the six-year period through 2020, total onshore gathering and transmission pipelines increased by 299 miles per year on average, from 308,951 miles in 2015 to 310,447 miles in 2020. Most of this total increase was the result of an increase in transmission line mileage in Class 1 locations.

Table 2 also shows the estimated mileage of Type C gathering lines newly covered by the Expansion of Gas Gathering Regulation (86 FR 63266, November 15, 2021). Type C gathering lines consist of an estimated 90,863 miles of onshore gas gathering lines in Class 1 locations that have outer diameters of 8.625 inches or greater and operate at higher stress levels or pressures. The reporting and safety requirements applicable to Type C gas gathering lines include leakage surveys for a subset (approximately 20,336 miles) of pipelines greater than or equal to 8.625 inches in diameter and located where a structure intended for human occupancy is located within the potential impact radius (PIR) and pipelines greater than 16 inches in diameter irrespective of the PIR criterion.

As of 2020, approximately 98 percent of the total mileage of regulated gas gathering (Types A, B or C) and gas transmission pipelines was onshore. As of the same year, nearly all part 192-regulated gathering lines and transmission lines transported natural gas.[8]

Table 2: Historical mileage of regulated gas gathering and gas transmission lines by class location and year (miles)

Segment	Class[1]	2015	2016	2017	2018	2019	2020	Average annual change, 2015-2020
Offshore								
Gathering	N/A	6,164	6,345	6,242	6,201	5,851	5,907	-51
Transmission	N/A	3,831	3,298	3,157	3,106	3,442	2,854	-195
Reported total	**N/A**	**9,995**	**9,643**	**9,399**	**9,307**	**9,293**	**8,761**	**-247**
Onshore								
Type A/B gathering[2]	1	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	2	7,393	7,171	7,476	7,246	7,537	6,999	-79
	3	4,202	4,326	4,349	4,408	4,345	4,357	31
	4	24	22	29	36	21	13	-2
	Total	**11,619**	**11,519**	**11,853**	**11,690**	**11,903**	**11,368**	**-50**
Transmission	1	232,273	232,264	232,781	233,964	234,170	234,178	381
	2	30,049	30,002	30,327	30,028	30,260	30,259	42
	3	34,065	33,853	33,539	33,576	33,613	33,775	-58
	4	944	927	932	839	844	866	-15
	Total	297,331	297,046	297,580	298,407	298,886	299,078	349
Reported total	**Total**	**308,951**	**308,566**	**309,433**	**310,097**	**310,790**	**310,447**	**299**
Estimated Type C gathering[3]	1	No data	No data	No data	No data	No data	90,863	No data[4]

N/A: Not applicable

[1] Class locations are defined at § 192.5. A Class 1 location is an offshore area or any class location unit with 10 or fewer buildings intended for human occupancy within the class location unit. A Class 2 location is any class location unit with more than 10 but fewer than 46 buildings intended for human occupancy within the class location unit. A Class 3 location is any class location unit with 46 or more buildings intended for human occupancy or an area where the pipeline lies within 100 yards of either a building or a small, well-defined outside area that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period within the class location unit, and a Class 4 location is any class location unit where buildings with 4 or more stories above ground are prevalent.

[2] Includes both onshore Type A and Type B part 192-regulated gathering lines. Type A gathering lines are those made of metallic pipe and a MAOP more than 20 percent of the SMYS, or non-metallic pipe with MAOP more than 125 psig. Type B gathering lines are those made of metallic pipe with MAOP less than 20 percent of SMYS, or non-metallic pipe with MAOP less than 125 psig.

[3] The values reflect estimated mileages of newly regulated Type C gas gathering lines in 2021, based on the analysis of the Expansion of Gas Gathering Regulation (PHMSA, 2021c) where PHMSA estimated that the mileage of these lines grows by 1.325 percent annually based on changes in the mileage of regulated onshore Type A/B gathering lines.

Source: Gas Transmission and Gathering Annual Report. Part L: Miles of Pipe by Class Location (6/1/2021 data release)

The leakage survey requirements also apply to offshore platform piping and riser piping above the waterline. These pipelines are subject to the same requirements as onshore gas transmission pipelines. PHMSA does not have data on the amount of piping associated with offshore platforms. The exact number of offshore platforms that may be subject to gas leakage detection

8 The 2020 Gas Transmission and Gathering Annual Report shows 16 miles of gathering lines transporting landfill gas. The same source shows 1,604 miles of transmission lines transporting gases other than natural gas, including ethylene, landfill gas, synthetic gas, and various other gases.

requirements is uncertain, but the Bureau of Safety and Environmental Enforcement (BSEE) Platform Structures Online Query system shows 1,264 fixed platforms in the Outer Continental Shelf (OCS) (BSEE, 2022).[9] The database does not indicate the product(s) associated with each active platform or of the number of wells associated with each platform; separate data from the Energy Information Administration (EIA) show 499 offshore gas producing wells and 2,269 gas producing oil wells in the Federal Offshore area of the Gulf of Mexico in 2020 (Energy Information Administration, 2022b). Using the 1,264 active platforms as an upper bound of the number of offshore platforms that produce gas[10] and assuming each platform has 100 to 200 feet of piping (PHMSA BPJ, based on field experience and firsthand observation of offshore platforms in state waters and the Gulf of Mexico)[11] translates into a total of approximately 25 to 50 miles of platform and riser piping subject to leakage survey requirements.

As described in section 4.1, 49 CFR 192.706 currently provides differentiated leakage survey requirements for odorized and non-odorized Class 3 or Class 4 lines. The proposed rule continues to provide differentiated requirements for odorized and non-odorized Class 3 and Class 4 transmission lines. Operators do not provide detailed information on the mileage and class location of odorized lines in their gas transmission annual reports. For the analysis under both the baseline and proposed rule, PHMSA assumes that all intrastate Class 3 and Class 4 natural gas transmission lines are odorized and all other lines (lines transporting other gases, and natural gas Class 1 and Class 2 transmission lines, interstate Class 3 and Class 4 transmission lines, and gathering lines) are not odorized. This assumption affects the modeled frequency of leakage surveys for different types of transmission lines under the baseline and proposed rule. See section 4.1 for additional details.

The proposed rule also provides differentiated leakage survey requirements for pipe with a known leak or incident history ("leak prone pipe") and gas transmission pipelines in high consequence areas (HCAs). Pipelines made of cast and wrought iron and bare steel are recognized as having a higher likelihood of developing leaks (American Gas Association (2013); Weller *et al.*, 2020). For purposes of this analysis, PHMSA assumes that leak prone pipe consists of bare steel pipe mileage as reported in operators' annual reports and projected over the period of analysis. [12]

Based on PHMSA's 2020 Gas Transmission and Gathering Annual Report data, 7 percent of transmission lines are in HCAs on average across all operators. For purposes of this analysis and in the absence of more detailed data on the distribution of these lines, PHMSA calculated the percentage of lines in HCAs by operator and assumed that this percentage is uniform across pipeline class location and material. PHMSA welcomes input and data on the joint distribution of

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9 See https://www.data.bsee.gov/Platform/PlatformStructures/Default.aspx; data accessed February 1, 2022.

10 The count of 1,264 active platforms is smaller than estimates of 1,800 Federal platforms and 1,300 facilities in state waters in Gorchov Negron *et al.* (2020) who surveyed methane emissions over the Gulf of Mexico in 2018.

11 The estimate is based on field experience of PHMSA subject matter experts and firsthand observations of offshore platforms in state waters and the Gulf of Mexico.

12 While cast iron pipe is also generally considered more leak-prone, PHMSA annual reports show no cast iron transmission or part 192-regulated gathering line mileage.

mileage inside and outside of HCA by class location and material to refine this estimate for the final rule analysis.[13]

For each operator and relevant subset of mileage (*e.g.*, odorized lines), PHMSA used the annual average changes over the 2015-2020 period to extrapolate onshore mileage through 2038. For Type C gathering lines, PHMSA used a previously developed estimate of the annual growth rate of 1.3 percent (PHMSA, 2021c).[14] In the absence of specific data addressing Type C gas gathering pipelines, the data on Type A and B are a reasonable basis for estimating the change in pipeline mileage. Table 3 summarizes these projections for selected years.

Table 3: Projected mileage of onshore gas gathering and gas transmission lines by year (miles)

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

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

3.1.2 Gas Distribution

As described in sections 2.1.5 and 4.2 and in Appendix A to this PRIA, PHMSA used distribution main mileage as the basis for estimating the costs of leakage surveys and leak repairs for distribution mains and associated service lines. PHMSA assumed that operators survey both mains and connected service lines at the same time. This assumption is consistent with the unit costs PHMSA used its analysis which are inclusive of surveys on both mains and services but are expressed on the basis of main mileage. This discussion focuses on the universe of gas mains.

Table 4 summarizes the mileage of gas distribution mains by material for calendar years 2015 through 2020. Over this period, distribution mains mileage increased at an annual average rate of 10,561 miles to a total of 1.33 million miles in 2020. Plastic main mileage increased by an

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13 The 7 percent share is based on annual report data. Operators must report the miles of pipelines in HCAs, the miles of pipelines by class location, and the miles of pipelines by material, but not combinations of those parameters. PHMSA therefore had to make assumptions regarding the joint distributions. PHMSA first divided mileage into leak prone (bare steel) and non-leak prone, then applied the share by class and/or share in HCA/non-HCA.

14 While the mileage of regulated Type A and Type B gas gathering lines declined in 2015-2020, the recent mileage still represents an increase relative to earlier years. Annual reports for the respective years show 10,232 miles of Type A and Type B gathering pipelines in 2012 and 11,368 miles in 2020.

average of 16,222 miles per year, or a 2.2 percent annual growth rate, while the mileage of most other types of mains declined as operators replaced some aging pipelines with plastic pipes.

PHMSA used annual average operator-, pipe material-, and commodity-specific changes over the 2015-2020 period to extrapolate gas distribution mains mileage through 2038, starting from the mileage reported by each operator in 2020. Table 5 summarizes projected mileage of distribution mains for selected years of the 2021-2038 analysis period.[15] These projections are based on historical trends and do not reflect the effects of incentive programs for replacing cast iron, bare steel pipe or other legacy pipelines, such as PHMSA's Natural Gas Distribution Infrastructure Safety and Modernization Grants program, which provides funding to municipally or community-owned gas distribution facilities for the purposes of replacing legacy pipelines.[16]

Table 4: Historical mileage of gas distribution mains by pipe material and year (miles)

Pipe material	2015	2016	2017	2018	2019	2020	Average annual change, 2015-2020
Bare Steel, Unprotected	39,652	37,331	35,281	33,373	31,479	30,183	-1,894
Coated Steel, Unprotected	20,090	19,551	19,500	19,119	18,873	18,003	-417
Bare Steel, Protected	11,835	11,515	11,148	10,755	10,621	10,268	-313
Coated Steel, Protected	467,941	467,657	465,889	464,698	462,799	460,604	-1,467
Plastic	706,395	721,575	738,705	755,053	772,010	787,507	16,222
Cast Iron	27,765	26,201	24,471	22,868	21,273	19,989	-1,555
Ductile Iron	575	547	536	513	493	476	-20
Copper	17	16	15	12	11	8	-2
Reconditioned Cast Iron	21	21	27	28	33	34	3
All Others	1,277	1,361	1,344	1,313	1,317	1,299	5
Total	**1,275,566**	**1,285,777**	**1,296,916**	**1,307,733**	**1,318,909**	**1,328,372**	**10,561**

Data include all gas commodities.
Source: Gas Distribution Annual Report. Part B: System Description (6/1/2021 data release)

Table 5: Projected mileage of gas distribution mains by pipe material and year (miles)

Pipe material	2021	2026	2031	2036
Bare Steel, Unprotected	28,948	23,995	20,100	17,461
Coated Steel, Unprotected	17,667	16,341	15,544	14,917
Bare Steel, Protected	10,221	10,714	11,437	12,325
Coated Steel, Protected	460,763	462,090	463,669	465,314

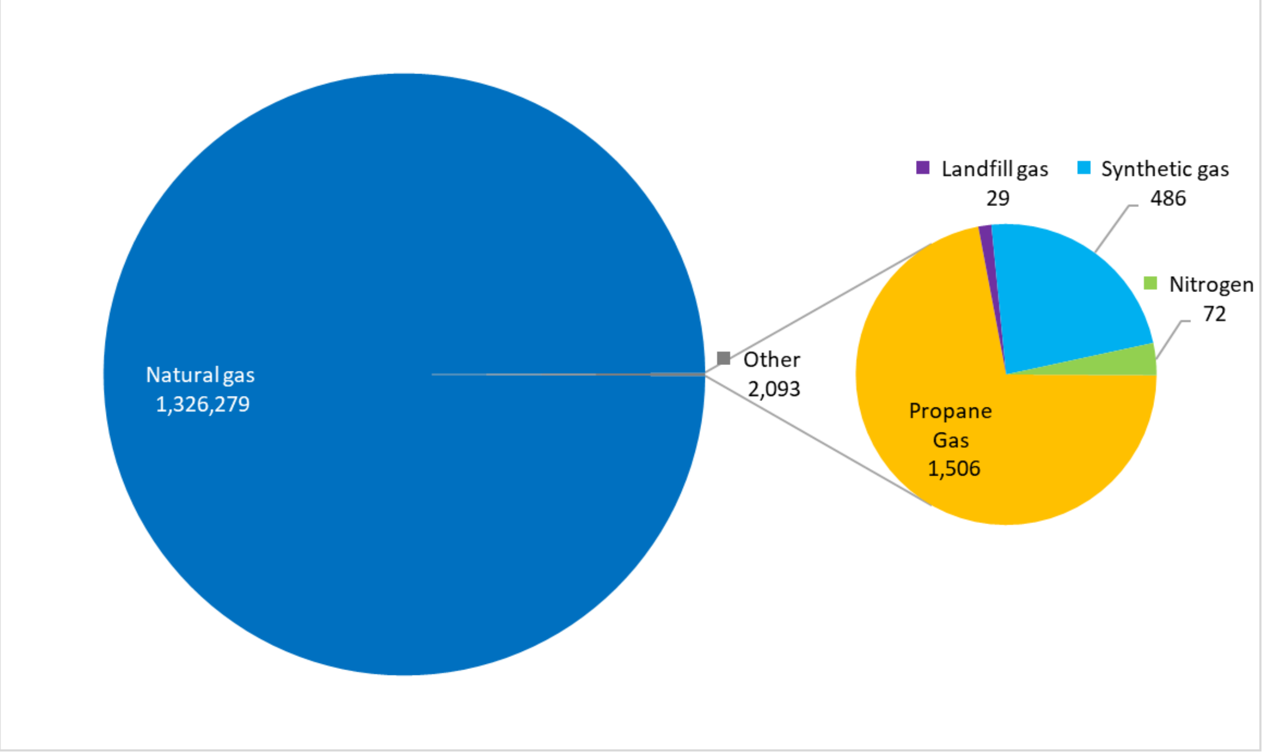
15 PHMSA uses operator-, pipe material-, and commodity-specific annual mileage changes between 2015 and 2020 to project mileage for each year during the 2021-2038 period. As a result, total year-to-year mileage change in Table 5 may differ from that shown in Table 4 based on the aggregate mileage reported to PHMSA in each year. For example, whereas the total mileage of protected bare steel has generally declined in 2015-2020, the total changes across operators reporting mileage in 2020 are positive. A review of the data reveals 14 operators with protected bare steel mains in 2015 that no longer reported data in 2020. A least some of the pipelines changed ownership and are being reported under a different operator ID. For example, one operator (SourceGas LLC; Operator ID 10030) reported nearly 350 miles of protected bare steel mains in 2015 but submitted no report in 2020. Research of this operator shows it is now part of Black Hills Energy (Operator ID 15359). Further, some operators reporting protected bare steel mains in 2020 did not submit reports in 2015.

16 The November 15, 2021, the Bipartisan Infrastructure Law (Pub. L. 117-57) authorized PHMSA's Natural Gas Distribution Infrastructure Safety and Modernization Grants program and appropriated $200 million per year for fiscal years 2022 – 2026.

Table 5: Projected mileage of gas distribution mains by pipe material and year (miles)				
Pipe material	**2021**	**2026**	**2031**	**2036**
Plastic	804,024	886,833	969,750	1,052,681
Cast Iron	18,905	13,951	10,280	7,454
Ductile Iron	458	373	300	232
Copper	7	3	3	2
Reconditioned Cast Iron	36	43	51	60
All Others	1,313	1,429	1,564	1,706
Total	**1,342,342**	**1,415,771**	**1,492,698**	**1,572,152**
Source: PHMSA analysis				

The proposed rule requirements apply to all gas distribution. As shown in Figure 1, distribution mains transporting natural gas account for 99.8 percent of the total mileage reported to PHMSA (1.33 million miles), with mains transporting propane gas, synthetic gas, nitrogen, and landfill gas accounting for the balance (2,093 miles).

Figure 1: 2020 gas distribution main mileage by commodity.



49 CFR 192.723 currently provides differentiated requirements for distribution mains inside and outside of business districts. The gas distribution annual reports do not include data on the shares of each distribution system located in business districts, nor does 49 CFR part 192 specifically define “business district.” Instead, each operator can delineate the portions of their system that meet the general concept of business district as a “place whose primary function is the conduct of businesses” and where the operator must conduct leakage surveys annually (PHMSA, 1995). For this analysis, PHMSA assumed that 5 percent of the distribution main mileage is located in business districts, with this share applied uniformly across operators and pipe materials. PHMSA welcomes feedback and data on the mileage of distribution mains and services that operators classify as being in business districts.

3.1.3 Number of Pipeline Operators

In 2020, there were 1,308 unique operators of gas transmission and part 192-regulated Type A and Type B gas gathering lines.[17] Table 6 shows the number of operators by segment, location (onshore, offshore), and type of commodity transported. PHMSA does not have data on the operators of Type C gathering lines since they have not been required to report to PHMSA until recently. For this analysis, PHMSA assumed the same firms that operate Type A and Type B gathering lines also operate Type C gathering lines, *i.e.*, a total of 378 operators operate part 192-regulated gathering lines.[18] PHMSA plans to update this assumption when operators submit their annual reports for 2022, but for the purpose of this analysis, PHMSA also estimated the costs of the proposed rule for an additional 1,591 operators that may be associated with Type C gathering lines based on the assumption that 80 percent of the Type C gathering lines mileage is operated by different entities (ICF International, 2016).[19]

Table 6: Gas gathering and gas transmission operators in 2020, by pipeline location and transported commodity

Segment	Location	Natural Gas	Other Gas	Total
Type A and Type B gathering[1]	Onshore	247	8	251
	Offshore	45	1	45
	Total	374	8	378
Transmission	Onshore	1,017	114	1,096
	Offshore	36	2	36
	Total	1,019	114	1,098
Total	Onshore	1,098	117	1,180
	Offshore	58	2	58
	Total	**1,226**	**117**	**1,308**

[1] For this analysis, PHMSA assumes that the same operators are associated with regulated Type C gas gathering lines. PHMSA also conducted a sensitivity analysis that estimates the costs of the proposed rule for an additional 1,591 operators that may be associated with Type C gathering lines.
Source: Gas Transmission and Gathering Annual Report. Part A: Operator Information (6/1/2021 data release)

Based on data reported to PHMSA in the Gas Distribution Annual Report (see Part B: System Description in 6/1/2021 data release), there were 1,322 unique operators of gas distribution systems across 50 states plus the District of Columbia and Puerto Rico in 2020.[20] Texas and California had the largest mileage of distribution mains and services. As a group, the top-15

17 See footnote in Table 2 for definition of Type A and Type B gas gathering lines.

18 As noted in the RIA for the Expansion of Gas Gathering Regulation, PHMSA estimated that 97 percent of the mileage of newly regulated Type C gas gathering pipelines is attributable to operators with previously regulated pipelines (PHMSA, 2021c).

19 The estimate of additional operators is based on an average of 45.7 miles of gathering lines per operator (based on 17,275 miles and 378 operators of Type A and B gathering lines in 2020) and 72,690 miles of Type C gathering lines (80 percent of 90,863 miles of Type C gathering lines in 2020).

20 This count reflects unique operator IDs reporting non-zero mileage of natural gas mains. Fifty-one operators operate in two or more states. Some operators report zero mains mileage.

states[21] accounted for nearly two thirds of service connections nationwide, 61 percent of main miles, and 44 percent of operators.

3.1.4 Other Gas Facilities

Some proposed rule requirements (*e.g.*, large-volume release reports, self-implementing provisions to mitigate vented and other emissions) also apply to LNG facilities and UNGSFs. Based on the Liquid Natural Gas Facility Report (see Part B: Plant Description, Type, and Function in 8/1/2022 data release), there were 87 entities operating a total of 165 LNG facilities in service across 38 states in 2020. Six states (LA, TX, GA, MD, MA, MS) had LNG marine terminals, whereas the remaining 32 states had LNG facilities serving as storage or other functions.[22]

Based on the Underground Natural Gas Storage Facility Report (8/1/2022 data release), A total of 127 entities were operating 403 UNGSFs in 2020. These facilities consisted of 455 reservoirs and 17,054 wells across 31 states. Six states (MI, IL, TX, LA, PA, and OH) accounted for approximately half of the national total gas capacity, and also half of the number of operators.

3.2 Natural Gas Leaks

3.2.1 Gas Gathering and Gas Transmission

Operators report to PHMSA the number of leaks eliminated (*i.e.*, repaired) each year as part of their Transmission and Gathering Annual Report. Figure 2 shows the total leaks eliminated or repaired during 2015-2020 by cause. Gas gathering and gas transmission operators reported an average of 1,640 leaks each year during that period. The majority of leaks were due to the reporting categories of "corrosion" (including external corrosion, internal corrosion, and stress corrosion cracking), "manufacturing," "construction," and "equipment"[23] in gas transmission pipelines in non-HCA locations.

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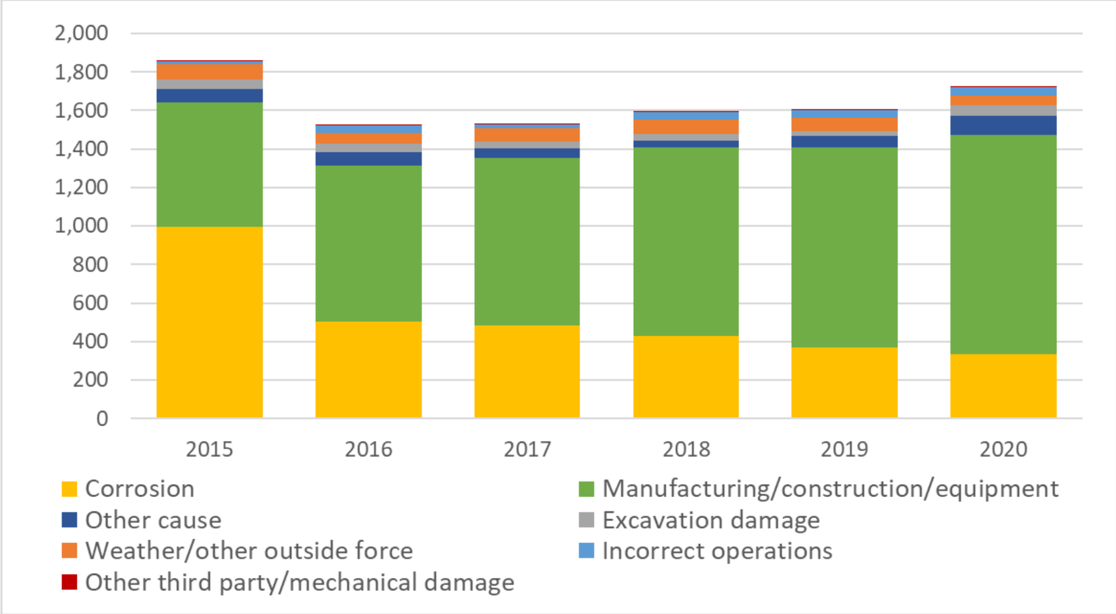
21 Based on data reported to PHMSA in the Gas Distribution Annual Report. Part B: System Description (6/1/2021 data release), the top-15 states in decreasing order of main miles are TX, CA, IL, MI, OH, NY, PA, GA, IN, TN, WI, CO, NJ, MN, and NC.

22 Marine terminal function includes marine terminal for import, export, or both import and export; Storage function includes storage with or without liquefaction; Other functions include vehicular fuel, nitrogen rejection unit, and other.

23 The instructions for the Gas Gathering and Transmission Annual Report describe these categories as follows:
Manufacturing: includes releases or failures caused by a defect or anomaly introduced during the process of manufacturing the pipe, including seam defects and defects in the pipe body or pipe girth weld.
Construction: includes releases or failures caused by a dent, gouge, excessive stress, or some other defect or anomaly introduced during the process of constructing, installing, or fabricating pipe (or welds which are an integral part of pipe), including welding or other activities performed at the facility.
Equipment: includes releases from or failures of items other than pipe or welds, and includes releases or failures resulting from: malfunction of control/relief equipment including valves, regulators, or other

Figure 2: Total number of gas gathering and gas transmission leaks eliminated or repaired in 2015-2020, by cause



Source: Gas Gathering and Transmission Annual Report (6/1/2021 data release).

3.2.2 Gas Distribution

Operators report to PHMSA the number of leaks eliminated each year as part of their Gas Distribution Annual Report. Figure 3 shows the total main line leaks eliminated or repaired in 2015-2020 by cause. Distribution operators reported an average of 124,242 leaks on mains eliminated or repaired each year during that period; an average of 107,231 leaks involved causes other than excavation damage. These leaks included an average of 42,553 leaks per year (Figure 4) that operators determined to present an existing or probable hazard to persons or property and which required immediate repair or continuous action until the conditions are no longer hazardous. This category corresponds to "hazardous leaks" that must be repaired pursuant to §192.703(c), and to grade 1 leaks in the NPRM. As such, the annual reports only cover a small subset of all existing gas distribution leaks. Importantly, any insight that can be derived from the annual reports would not account for the full set of leaks targeted by the proposed leak detection and repair provisions under the proposed rule, or the proposed expanded scope of "hazardous"

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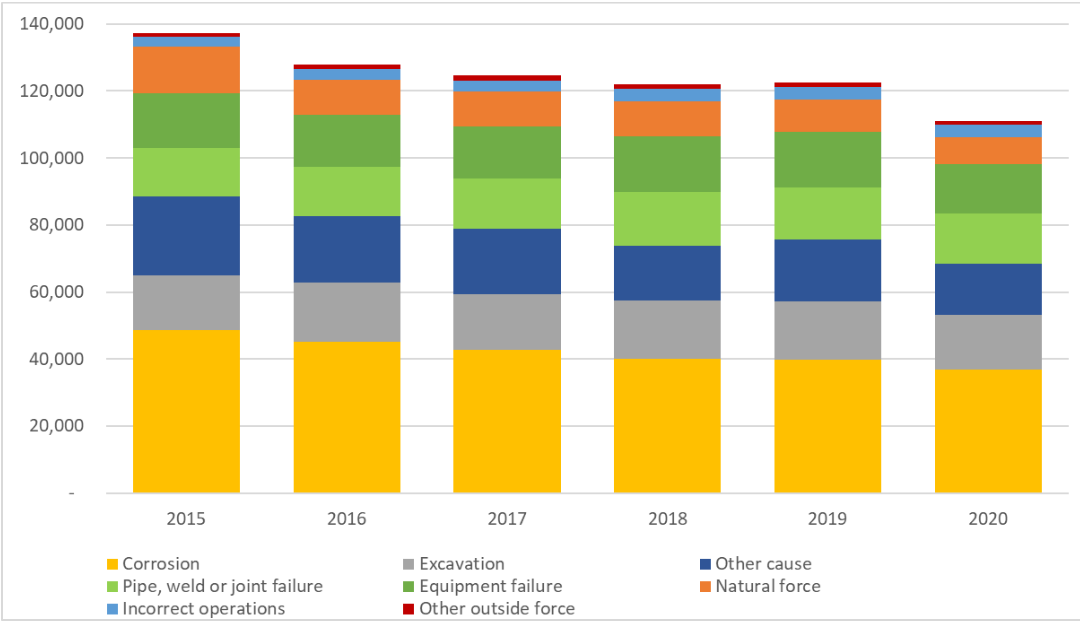
instrumentation; compressors or compressor-related equipment; various types of connectors, connections, and appurtenances; the body of equipment, vessel plate, or other material (including those caused by: construction-, installation-, or fabrication-related and original manufacturing-related defects or anomalies; and low temperature embrittlement); and, all other equipment-related releases or failures.

leaks to be reported to PHMSA to go beyond leaks hazardous to public safety to also include leaks hazardous to the environment.[24]

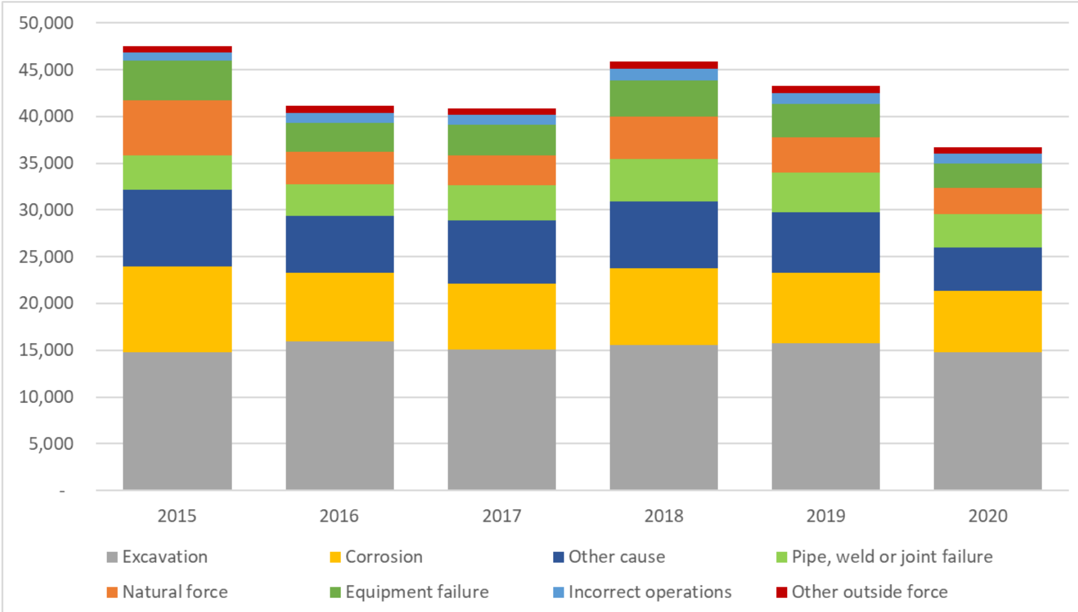
Figure 3: Total number of gas distribution main leaks eliminated or repaired in 2015-2020, by cause



Source: Gas Distribution Annual Report (6/1/2021 data release).

24 As detailed in the NPRM, 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; the number (by grade) of unrepaired leaks at the conclusion of the annual reporting period; and the estimated aggregate and average per-leak emissions from leaks 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 a distinction between hazardous leaks, other leaks, or other gas releases allegedly too small to merit reporting.

Figure 4: Number of gas distribution mains hazardous leaks eliminated or repaired in 2015-2020, by cause

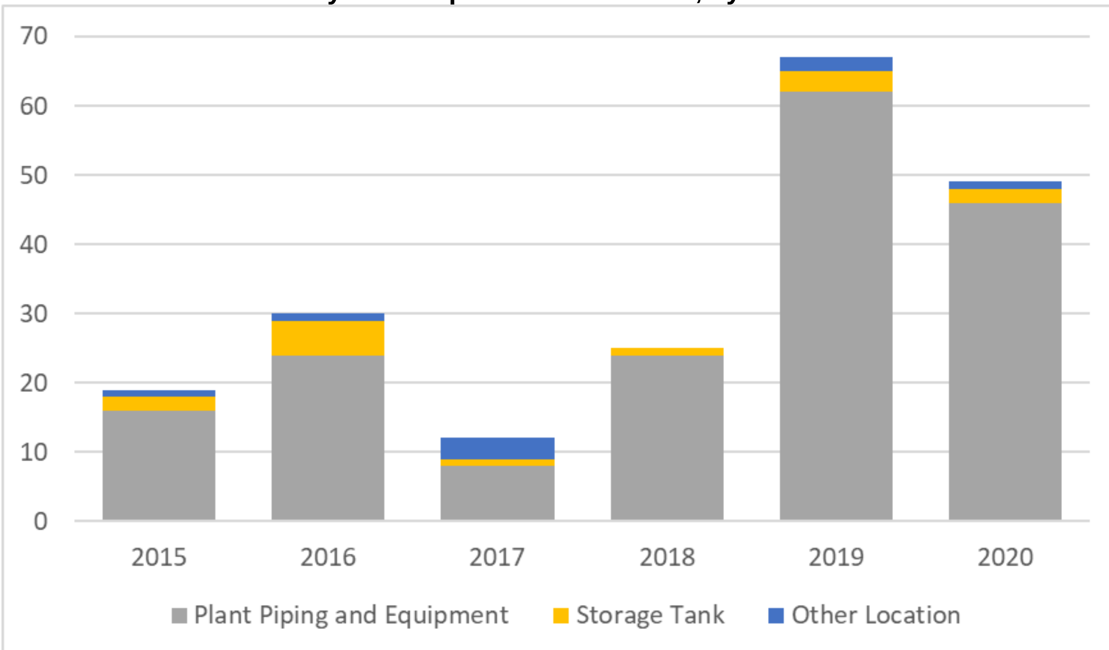


Source: Gas Distribution Annual Report (6/1/2021 data release).

3.2.3 Other Gas Facilities

Operators of LNG facilities and UNGSFs report to PHMSA each year on the characteristics and operational status of their facilities. For LNG facilities, the reported information includes the number of leaks resulting in a release detected and repaired, by location and cause. Figure 5 shows the total leaks in 2015-2020 by location within the LNG facility. The vast majority of LNG facility leaks originated from plant piping and equipment, and within those leaks, most were attributed to "equipment failure" (*e.g.*, 36 out of the 46 leaks reported in 2020 as originating from plant piping and equipment were caused by equipment failure). Annual reporting by UNGSFs started in 2017, with operators required to report the number of wells with casing, wellhead, or tubing leaks as well as the number of wells undergoing certain repairs and other maintenance activities. In total in 2020, UNGSF operators reported a total of 56 well leaks, out of a total of 13,984 injection and/or withdrawal wells.

Figure 5: Number of LNG facility leaks repaired in 2015-2020, by location



Source: Liquefied Natural Gas Facilities Annual Report (8/1/2022 data release).

3.3 Methane Emissions

EPA's Greenhouse Gas Inventory (GHGI) provides the federal government's estimates of U.S. greenhouse gas (GHG) emissions, including methane from natural gas pipeline systems. The latest inventory covers the period of 1990-2020 (EPA, 2021e; EPA, 2022e). The inventory incorporates emissions reported by major GHG sources to the GHG Reporting Program (GHGRP) and estimates derived using emission factors and activity data (EPA, 2021a; EPA, 2022a). The most recent GHGI estimates for the natural gas system are based on emission factors from various sources, including EPA & Gas Research Institute (GRI) (1996) and Lamb *et al.* (2015).[25]

Table 7 summarizes methane emission estimates for natural gas segments of the Oil and Gas sector. Estimates relevant to sources regulated by PHMSA include 0.14 million metric tons (MMTon) of methane for gathering pipeline leaks and blowdowns, 0.22 MMTon for transmission pipelines (including both leaks and venting), and 0.55 MMTon from distribution systems, including 0.20 MMTon from distribution pipeline leaks. Only a fraction of gas gathering pipeline emissions is expected to come from PHMSA-regulated lines in scope of this

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[25] See tables 3.6-6 and 3.6-17 of Annex 36 of the 2021 GHGI for the source and methodology of each methane emissions factor (EPA, 2021a; EPA, 2022a).

proposed rule since regulated gathering lines account for only 23 percent of the total mileage of gas gathering lines in the United States.[26]

Table 7: Inventoried methane emissions from natural gas systems in 2020	
Natural gas industry segment and source	**Net emissions (MMTon CH_4)**
Exploration	**0.01**
Production	**3.55**
Onshore production	1.97
Offshore production	0.04
Gathering and boosting	1.54
Pipeline leaks[1]	0.13
Pipeline blowdowns[1]	0.01
All other gathering and boosting sources	1.40
Processing	**0.49**
Transmission and storage	**1.62**
Compression	1.38
Pipeline leaks[2]	<0.01
Pipeline venting	0.22
LNG storage and import/export terminals	0.02
Distribution	**0.55**
Pipeline leaks	0.20
Meter/regulator	0.04
Customer meters	0.24
Routine maintenance (pressure relief, blowdown)	0.00
Mishaps/dig-ins	0.07
Total[3]	**6.23**

[1] EPA estimated emissions from pipeline leaks and blowdowns based on 438,971 miles of gathering lines.
[2] Estimated emissions from pipeline leaks were 3.3 kt CH_4 in 2020, *i.e.*, greater than zero but less than the 0.01 MMTon CH4 data resolution of this table.
[3] Total may not add up due to independent rounding.
Source: EPA, 2022a; EPA, 2022e

EPA estimated a methane emission factor of 288.5 kg/mile for gas gathering and boosting pipeline leaks and 10.9 kg/mile for gas transmission and storage pipeline leaks in the GHGI (EPA, 2021e; EPA, 2022e). For this analysis, PHMSA used the GHGI emission factors to estimate the number of leaks on gas gathering and transmission pipelines, the methane emissions associated with these leaks, and the associated costs and benefits of the proposed rule. Using the modeling approach described in section 2.1.5 and in Appendix A, PHMSA estimated average baseline emissions from transmission pipelines at 0.004 MMTon CH_4 per year over the period of analysis, and baseline emissions from regulated gathering pipelines at 0.041 MMTon CH_4 per year. Modeled baseline emissions increase over the period of analysis along with pipeline mileage.

Various researchers have developed alternative methane emission estimates using either top-down and bottom-up assessments for selected industry segments or sources, or a combination of

[26] In 2020, PHMSA regulated 11,368 miles of onshore gas gathering lines, compared to a total of 438,971 miles of gathering lines in the GHGI (EPA, 2021e; EPA, 2022a; EPA, 2022e). The 2021 Expansion of Gas Gathering Regulation (86 FR 63266, November 15, 2021) added an estimated 90,863 miles of Type C gathering lines to the regulated universe and brought the PHMSA-regulated share to approximately 23 percent of the GHGI total mileage.

approaches. Some of these studies' findings significantly differ from GHGI estimates. For example, a study by Alvarez *et al.* (2018), estimated methane emissions that were approximately 60 percent higher than the corresponding GHGI estimates for the year 2015 (and also significantly higher than those in EPA's GHGI for the year 2020), with the largest difference observed for the production segment. They attributed the differences to EPA's inventory methods failing to account for significant releases during abnormal operating conditions. A survey of the Permian oil and gas production area by Chen *et al.* (2022) showed emission rates for gathering line leaks that were two orders of magnitude larger than estimates derived from the GHGI and PHMSA data (1,452 vs 11.4 metric tons CH_4/leak-year).[27] Weller *et al.* (2020) focused specifically on the natural gas distribution segment and estimated emissions that were five times larger than those in the 2017 GHGI (0.69 MMTon vs. 0.14 MMTon).[28] Weller *et al.* (2020) attributed the differences to a larger number of leaks and better characterization of the upper tail of the skewed distribution of emission rates.

Table 8 compares emission factors for distribution systems that EPA uses in the GHGI (based on EPA & GRI (1996) and Lamb *et al.* (2015)) to those developed by Weller *et al.* (2020). Throughout the analysis, PHMSA used values from Lamb *et al.* (2015) and Weller *et al.* (2020) to estimate ranges of the number of leaks present across the distribution system, the methane emissions associated with these leaks, and the associated costs and benefits of the proposed rule. Comparing these two sources reveals that Weller *et al.* (2020) found much greater incidence of leaks in plastic and coated steel mains (nearly 9 times and 6 times greater, respectively), and much smaller incidence in bare steel and cast iron mains (approximately one fifth and one third, respectively) than Lamb *et al.* (2015). Emission rates in Weller *et al.* (2020) were consistently higher across all material types, by as much as six times higher for plastic mains. The Weller *et al.* (2020) emission rates were more comparable to those in EPA & GRI (1996).

Table 8: Gas distribution system methane emission factors from selected studies.

Pipe material	EPA & GRI (1996)		Lamb *et al.* (2015)		Weller *et al.* (2020)	
	Leak incidence (leak/mile)	Emissions rate (g/min-leak)	Leak incidence (leak/mile)	Emissions rate (g/min-leak)	Leak incidence (leak/mile)	Emissions rate (g/min-leak)
Bare (unprotected) steel	1.82	1.91	2.51	0.77	0.51	2.24
Cast iron	N/A	3.57	2.88	0.90	1.00	1.72
Coated (protected) steel	0.14	0.76	0.11	1.21	0.61	2.00
Plastic	0.18	1.88	0.05	0.33	0.43	2.03
Total (all materials)	0.35	N/A	0.23	N/A	0.51	N/A

N/A: Value not available.
Source: Adapted from Table 1 and Table 2 in Weller et al. (2020)

Using the modeling approach described in section 2.1.5 and in Appendix A, PHMSA estimated average baseline emissions from distribution pipelines using emission factors from Lamb *et al.* (2015) and from Weller *et al.* (2020) and accounting for changes in distribution pipeline mileage and pipe materials over time. Over the period of 2024-2038, the modeled baseline emissions

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27 Section 6.2 presents alternative estimates for gathering lines derived from field surveys in the Permian Basin oil and gas production area.

28 Emissions obtained by Weller *et al.* (2020) are also greater than the more recent GHGI estimates of pipeline leaks summarized in Table 7 for calendar year 2020: 0.20 MMTon CH_4.

average 0.32 MMTon CH_4 using factors from Lamb *et al.* (2015) and 1.6 MMTon CH_4 using factors on Weller *et al.* (2020).

3.4 Baseline Leak Detection and Repair Practices

The proposed rule sets performance criteria that could be met through a variety of leak detection technologies and practices, including some of the practices currently employed by operators of gas gathering, gas transmission, and gas distribution systems.

The Gas Piping Technology Committee (GPTC) "Guide for Gas Transmission, Distribution, and Gathering Piping Systems" outlines sample procedures for leak survey and grading, consistent with existing federal requirements (GPTC, 2018). Specifically, Appendix G-192-11 "Gas Leakage Control Guidelines for Natural Gas Systems (Methane)" describes survey and classification procedures and provides action criteria and examples by leak grades. These GPTC procedures are widely used across the industry and several states incorporate the GPTC guide by reference or build upon the guide in their regulations. Bull (2009) attributes the industry's broad acceptance of the procedures to the GPTC diverse membership across gas distribution, gathering and transmission systems, manufacturers, general interest groups, and federal and state regulators, and to the engagement and consensus building process used to develop the guide. Bull (2009) adds that "one of the most quoted and adopted sections of the guide is the 'Leak Classification and Action Criteria' from Appendix G-192-11. This leak classification system is used by many operators and is included in a number of state regulations." For the analysis, PHMSA generally assumed the GPTC guide procedures as the baseline, unless a state has promulgated alternative more stringent requirements, in which case the state requirements were used as the baseline.

3.5 Self-implementing Provisions of the PIPES Act of 2020

The proposed rule incorporates several self-implementing provisions under Section 114 of the PIPES Act of 2020 that mandate changes to inspection and maintenance plans to minimize releases of natural gas from pipeline facilities. The procedures must also address the remediation or replacement of pipelines known to leak based on their material, design, or past maintenance and operating history. The procedures must specifically address intentional venting during blowdown or other scheduled maintenance activities.

EPA estimated emissions from gas transmission venting and gas gathering and gas distribution line blowdowns at 232,761 MMTon CH_4 in 2020 (EPA, 2021e; EPA, 2022e). These estimates incorporate some reductions already achieved through voluntary initiatives. Several operators have already made methane capture technologies part of their operating procedures to minimize emissions from blowdowns (Southern California Gas Company, 2020, 2021; Southwest Gas Corporation, 2018). EPA estimated that, in 2019, participants in EPA's Methane Challenge program voluntarily reduced methane emissions from transmission pipeline blowdowns by a total of 74,971 MMTon, and those from distribution blowdowns by 192 MMTon.[29] To the extent that other pipeline operators have not yet taken steps voluntarily to reduce blowdown and venting emissions, the implementation of the provisions in the PIPES Act of 2020 will further reduce methane emissions.

Because these measures are mandated explicitly by the Act and are already in effect, PHMSA did not attribute the associated costs or benefits to the proposed rule. There is uncertainty, however, regarding the measures operators would implement in the absence of the clarifications included in this proposed rule. To inform understanding of the expected economic impacts of the statutory changes made by both Section 114 and the proposed rule, PHMSA evaluated the proposed rule relative to a pre-statutory baseline. This analysis is summarized in section 6.1 which provides the estimated costs and benefits of blowdown mitigation requirements.

3.6 Uncertainty and Limitations

Table 9 highlights the principal sources of uncertainties and limitations present in the assessment of baseline conditions.

Table 9: Principal sources of uncertainty in the assessment of baseline conditions.

Item	Sources of uncertainty
Leak data	As described in section 3.2, only a subset of leaks that occur each year are documented in annual reports due to the reporting criteria that focus on hazardous leaks and other leaks requiring repairs. As such, the leak incidence rate and other statistics derived from the reported data provides only a partial picture of existing leaks known to operators and/or repaired each year. For this analysis, PHMSA modeled leak incidence using alternate data sources, where available, that reflect the incidence of different types of leaks across pipeline segments. These data are also subject to limitations of the respective detection or reporting thresholds or estimation methods.
Current leak detection and repair practices	There is limited information about the leak detection and repair practices pipeline operators are implementing in the baseline, including the frequency of leakage surveys, survey methods used, and repair criteria and timelines. For this analysis, PHMSA generally assumed that operators follow GPTC recommendations unless state requirements are more stringent. To the extent that operators voluntarily survey their systems more frequently, this assumption understates the mileage surveyed in the baseline.
Type C gathering pipelines	There is uncertainty on the mileage and characteristics of regulated gas gathering pipelines. PHMSA expanded reporting requirements for gas gathering pipelines in 2021 (86 FR 63266, November 15, 2021), with the first annual report covering the newly covered lines due March 2023. This analysis relies on estimated mileage and operators.
Incentives for pipe replacement	The baseline analysis reflects historical trends. Incentive programs may accelerate the replacement of legacy pipelines relative to historical replacement rates, but these effects are difficult to project. Leak rates and leak incidence are both determined by the type of pipe (*e.g.*, cast iron, uncoated steel, plastic), age, and other factors, so that accelerating replacement of older, leak-prone pipes may affect the number of leaks and methane emissions in the baseline. To the extent that operators accelerate the rate at which they have been replacing leak-prone pipes with pipes that are less prone to leakage, then PHMSA's baseline scenario overstates leak incidence and emissions.

[29] EPA estimated voluntary reductions in emissions from transmission and distribution pipeline blowdowns of 1,874,273 and 4,800 metric tons carbon dioxide equivalent (74,971 and 192 metric ton CH_4), respectively, in the 2019 Best Management Practice and ONE Future Reporting Results Summary (https://www.epa.gov/natural-gas-star-program/methane-challenge-program-accomplishments; accessed August 17, 2021). Southern California Gas and Southwest Gas Corporation are both Methane Challenge program participants.

4 Cost Analysis

The following sections identify and discuss the incremental effects attributed to the proposed rule, relative to the baseline, and the associated costs. The discussion is organized by industry segment (gas gathering and gas transmission, gas distribution, other gas facilities), and by major rule requirement. Section 2.1.5 and Appendix A provide additional details on the analysis framework PHMSA used to estimate the costs of conducting leak surveys, repairs, and monitoring under the baseline and proposed rule.

4.1 Gas Gathering and Gas Transmission

4.1.1 Patrolling

The proposed rule will increase the minimum required frequency of visual right-of-way patrols on gas transmission pipelines, offshore gathering, and Type A regulated gas gathering lines to 12 times each calendar year, with intervals between patrols not exceeding 45 days, regardless of location. In the baseline, patrols on gas transmission and Type A gas gathering pipelines must be performed approximately one to four times per year, depending on the class location of the pipeline or if the pipeline crosses a road or railroad. The proposed rule also introduces requirements for monthly visual patrols of Type B and Type C gas gathering lines. These gathering lines are not subject to visual patrols in the baseline.

In the economic analysis for the expansion of regulated gas gathering, PHMSA estimated the cost of conducting patrols at $32 to $128 per mile depending on whether the additional patrols were added to an existing program or were part of a new program (PHMSA, 2021c).[30] Because patrolling practices are covered under existing part 192 personnel training regulations, PHMSA does not expect additional personnel training to be needed as a result of the proposed rule.

PHMSA assumes that operators of onshore and offshore gas transmission pipelines and Type A regulated gas gathering lines perform patrols at least once per month in the baseline. This assumption is informed by input PHMSA received from transmission operators who account for a significant share of the total transmission mileage and who patrol their lines at least once per month. For example, Pacific Gas and Electric (PG&E)'s Pipeline Patrol Program "seeks to conduct patrols of the entire transmission system monthly, as well as meet an internal goal to patrol pipelines located in High Consequence Areas (populated areas) a second time each month, as conditions permit" (Pacific Gas and Electric Company, 2019a; p.36). In the experience of PHMSA subject matter experts, this practice is common across transmission pipeline operators. Because Type A lines have operating conditions (*e.g.*, operating pressures) that are similar to those of transmission lines, PHMSA expects that operators use similar practices on both transmission and Type A gathering lines. For submerged offshore lines, PHMSA expects that operators will continue to look for visual evidence of leaks as they fly crews in and out of production areas, as they currently do. Given baseline practices, PHMSA estimates that the proposed enhanced patrolling requirements will result in no incremental costs for onshore and

30 Patrol costs were adjusted from the values given in 2018 dollars in PHMSA (2021c; $31 to $124) to 2020 dollars using the GDP deflator (1.03).

offshore transmission and Type A regulated gas gathering pipeline patrol requirements under the proposed rule.[31]

In estimating the incremental costs for the new monthly patrol requirements for Type B and Type C gathering lines, PHMSA assumed that operators would perform one of their monthly visual patrols at the same time as the annual leakage survey discussed in the next section, with the costs of this patrol reflected in the incremental costs of the leakage survey. PHMSA deems this a reasonable assumption since the inspection elements that would need to be covered during the patrol, such as observing surface conditions on and adjacent to the pipeline right-of-way to detect evidence of leaks or physical disturbances, are also part of a leak survey. PHMSA therefore estimated incremental costs specific to patrolling requirements based on 11 patrols annually.

Table 13 summarizes the incremental patrolling costs attributable to the proposed rule.

Table 10: Incremental patrolling costs over period of analysis (millions 2020$)

Year		Gathering[1]	Transmission
2024		$138	$0
2025		$140	$0
2026		$142	$0
2027		$144	$0
2028		$146	$0
2029		$148	$0
2030		$150	$0
2031		$153	$0
2032		$155	$0
2033		$157	$0
2034		$159	$0
2035		$162	$0
2036		$164	$0
2037		$167	$0
2038		$169	$0
3%	**Total present value (PV)**	**$1,865**	**$0**
	Annualized	**$152**	**$0**
7%	**Total PV**	**$1,464**	**$0**
	Annualized	**$150**	**$0**

[1] Incremental patrolling costs are associated only with the proposed rule requirements for Type B and Type C gathering lines only. There are no incremental patrolling costs for Type A gathering lines.
Source: PHMSA analysis

PHMSA welcomes comments and data on baseline practices implemented by gas gathering and transmission operators, including PHMSA's understanding that operators already patrol their onshore and offshore gas transmission, offshore gathering, and Type A part 192-regulated gathering lines monthly. PHMSA also welcomes comments and data on the assumption that

[31] To the extent that some operators do not already conduct monthly patrols of their onshore and offshore transmission and Type A regulated gas gathering pipeline, the analysis may understate the costs (and benefits) attributable to the proposed rule. For example, assuming the 933 operators with only intrastate transmission lines conduct patrols of their onshore lines once a year, the incremental costs of switching to monthly patrols may range between $35 million to $140 million per year (11 additional patrols × 99,129 pipelines miles for operators with only intrastate mileage (as of 2020) × $32 to $128 per mile).

operators of Type B and C gas gathering lines could conduct visual patrols concurrently with the leakage surveys discussed in the next section.

4.1.2 Leakage Surveys

For submerged offshore gathering and transmission lines, the proposed rule allows the use of human senses to detect leaks (*e.g.*, looking for sheen or bubbles on the water surface). As such, PHMSA expects that operators already conduct leakage surveys as part of baseline patrol practices discussed in section 4.1.1 (which are already required for offshore pipelines at least annually under §192.705), and that the proposed rule will therefore result in no incremental costs. Offshore gathering and transmission lines above the waterline, including platform piping, are subject to the proposed requirements for equipment and leakage survey for onshore lines. Operators can be expected to conduct annual leak surveys of accessible areas at least once a year as part of their regular maintenance of platform facilities. Therefore, the proposed requirements are not expected to result in incremental costs for platform operators.

In the baseline, onshore gas transmission lines that are not odorized must 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 lines, Type A and Type B gathering lines, and a subset of Type C gathering lines must be surveyed once each calendar year in the baseline. The subset of Type C gas gathering lines currently subject to leakage survey requirements are those greater than or equal to 8.625-inch in diameter and located where a structure intended for human occupancy is located within the PIR and those greater than 16-inch in diameter, irrespective of the PIR criterion. PHMSA estimated there were 20,336 miles of these lines in 2021 (PHMSA, 2021c). For other regulated Type C gathering lines, PHMSA conservatively assumed that operators do not conduct leakage surveys, although it is likely that some operators with different types of regulated gas gathering pipelines address their various lines in existing survey procedures.

The proposed rule will reduce the maximum interval between required leakage surveys of certain gas transmission and gathering pipelines. Table 11 and Table 12 show the number of leakage surveys per year required in the baseline and under the proposed rule, respectively. Overall, the proposed rule changes will affect requirements for a subset of gas transmission or regulated gas gathering lines that are leak-prone or in an HCA, and for regulated Type C gathering lines not currently subject to leakage survey requirements.

Table 11: Baseline gas gathering and transmission survey frequency (surveys per year)

Type	Class	Without odorant	Odorized
Type A/B gathering	Class 2	1	N/A[1]
	Class 3	2	N/A[1]
	Class 4	4	N/A[1]
Type C gathering	Class 1	0	N/A
	Class 1[2]	1	N/A
Transmission	Class 1	1	1
	Class 2	1	1
	Class 3	2	1
	Class 4	4	1

[1] Type A gathering lines are subject to the same survey requirements as transmission lines. However, for this analysis, PHMSA assumed that all lines other than Class 3 and Class 4 transmission lines are not odorized and therefore require 1, 2, or 4 surveys per year depending on the class location.

Table 11: Baseline gas gathering and transmission survey frequency (surveys per year)			
Type	**Class**	**Without odorant**	**Odorized**
[2] Subset of regulated Type C gathering lines subject to leakage survey requirements based on diameter and location. N/A: Not applicable *Source: 49 CFR 192.706*			

Table 12: Proposed rule gas gathering and transmission survey frequency (surveys per year)				
Type	**Class**	**Leak prone pipe[1] or pipe in HCA**	**Other (non-leak prone, non-HCA)**	
			Without odorant	**Odorized**
Type A/B gathering	Class 2	2	1	N/A[2]
	Class 3	2	2	N/A[2]
	Class 4	4	4	N/A[2]
Type C gathering	Class 1	N/A	1	N/A
Transmission	Class 1	2	1	1
	Class 2	2	1	1
	Class 3	2	2	1
	Class 4	4	4	1
N/A: Not applicable [1] PHMSA assumed that bare steel pipes are leak prone. PHMSA annual reports show no cast iron transmission or part 192-regulated gathering line mileage. [2] Type A gathering lines are subject to the same survey requirements as transmission lines. However, for this analysis, PHMSA assumed that all lines other than Class 3 and Class 4 transmission lines are not odorized and therefore require 1, 2, or 4 surveys per year depending on the class location. *Source: PHMSA analysis; reflects proposed rule requirements*				

PHMSA assumed bare steel pipes are leak prone.[32]

Natural gas in gathering lines is generally not odorized given where these lines fit within the gas transportation infrastructure. For this analysis, PHMSA assumed that intrastate Class 3 and Class 4 natural gas transmission lines are odorized, and all other lines operate without odorant, including gathering lines and lines that transport commodities other than natural gas (PHMSA best professional judgement [BPJ]). Based on annual gathering and transmission pipeline systems data reported in 2020, 0.3 percent of the total transmission mileage was in a Class 4 location and 11.3 percent was in a Class 3 location (PHMSA, 2021a).

PHMSA made general assumptions given the lack of data on which lines are odorized and not odorized as this information is not requested as part of the annual reports. The assumptions are reasonable given that there are no requirements to odorize natural gas in Class 1 and Class 2 locations. Odorization requirements apply to some Class 3 and Class 4 transmission pipelines, except where at least 50 percent of the pipeline downstream is in a Class 1 or Class 2 location (among other exceptions), among other criteria.[33] PHMSA used the intrastate designation as a

32 PHMSA annual reports show no cast iron transmission or part 192-regulated gathering line mileage.

33 § 192.625 Odorization of gas.
(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

proxy for pipelines that generally travel over shorter distances and do not change class locations. PHMSA realizes, however, that these are simplifying assumptions and gas transported by pipelines near large metropolitan areas is likely to be odorized, even for interstate pipelines. To the extent that these lines are odorized and are either leak prone or in an HCA, then the proposed requirement will increase the frequency of surveys to be conducted each year from the annual survey required under the baseline, to two or four surveys per year (for Class 3 and Class 4, respectively).

PHMSA estimated the cost of leakage surveys at $515 per mile based on information available from pipeline operators (Southern California Gas Company, 2014; PHMSA, 2021c).[34] This average unit cost reflects a combination of ground and aerial survey methods and ALD equipment. PHMSA did not find good estimates of the costs of conducting leak surveys using traditional survey methods only and therefore lacked sufficient information to determine whether the transition to ALD methods results in incremental costs on a per mile basis. PHMSA expects that incremental equipment costs may be offset by the greater efficiency of ALD survey methods, resulting in comparable unit costs (per mile). For this analysis, PHMSA applied the unit survey cost of $515 per mile uniformly to all pipelines in both the baseline and regulatory scenarios. Differences between the baseline and regulatory scenarios are hence driven by the survey intervals and number of miles inspected each year, the number of leaks detected, and the number of leaks repaired. PHMSA recognizes that the assumption that unit costs are the same for both the baseline and regulatory scenarios may overstate the cost of conducting leak surveys using traditional survey methods, and therefore underestimate the incremental costs of the proposed rule. PHMSA is requesting comments and data on unit costs for conducting surveys using traditional methods and those for conducting surveys using ALD methods, including whether new technologies and economies of scale could reduce those unit costs in the future.

Table 13 shows the incremental survey costs attributable to the proposed rule. As described in section 2.1.5 and detailed in Appendix A, these costs are derived by multiplying unit survey costs by the number of miles over which they apply each year under the baseline and proposed rule requirements, and then calculating the difference between the two scenarios to isolate the incremental costs attributable to the proposed rule. Since the unit survey costs are the same under

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(b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:

(1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

(2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975; (i) An underground storage field; (ii) A gas processing plant; (iii) A gas dehydration plant; or (iv) An industrial plant using gas in a process where the presence of an odorant: (A) Makes the end product unfit for the purpose for which it is intended; (B) Reduces the activity of a catalyst; or (C) Reduces the percentage completion of a chemical reaction;

(3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or

(4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.

34 PHMSA adjusted the value of $500 per mile provided in the original sources from 2018 dollars to 2020 dollars using the GDP implicit price deflator (1.03).

the baseline and regulatory scenarios, the additional costs are due to the more frequent surveys required under the proposed rule.

As described in Section 4.1.1, for Type C gas gathering lines, PHMSA assumed that the leakage survey is done concurrently with the visual patrol. In the case of transmission pipelines, the leakage surveys may be combined with a monthly patrol, but for the purpose of this analysis, PHMSA did not reduce the cost of the surveys to reflect any savings operators may realize by combining the activities.

Table 13: Incremental leakage survey costs over period of analysis (millions 2020$)

Year		Gathering	Transmission
2024		$38	$12
2025		$39	$12
2026		$39	$12
2027		$40	$12
2028		$40	$12
2029		$41	$12
2030		$41	$12
2031		$42	$12
2032		$42	$12
2033		$43	$12
2034		$43	$12
2035		$44	$12
2036		$45	$12
2037		$45	$12
2038		$46	$12
3%	**Total PV**	**$510**	**$150**
	Annualized	**$41**	**$12**
7%	**Total PV**	**$401**	**$119**
	Annualized	**$41**	**$12**

Source: PHMSA analysis

PHMSA welcomes comments and data on baseline leak detection practices implemented by operators of gas transmission and regulated gas gathering pipelines, distribution of pipeline mileage that is odorized, and assumptions regarding the unit costs of conducting leakage surveys over the pipeline network.

4.1.3 Leak Repairs

PHMSA proposes to set leak repair deadlines depending on the leak grade and the pipeline type and location. Specifically, PHMSA proposes that grade 1 leaks be repaired immediately. Grade 2 leaks on a gas transmission or Type A gathering pipeline, each located in a class 3 or class 4 location, would generally need to be repaired within 30 days of detection, whereas all other grade 2 leaks would need to be repaired within 6 months of detection. Finally, grade 3 leaks would generally need to be repaired within 2 years of detection.

These requirements are generally consistent with existing practices of gas gathering and transmission operators. Transmission systems operate at relatively high pressures and are susceptible to rupture, factors that can make leaks hazardous and justify higher priorities for repairs (PHMSA BPJ). Documents from transmission pipeline operators and state public utility commissions suggest that operators already make repairs faster than would be required under the proposed rule. For example, PG&E (2019a) repairs grade 3 leaks within 12 months of discovery. The State of California Public Utility Commission (CPUC) requires repairs of all grade 3 underground leaks upon discovery or within one year (State of California, 2015). PHMSA assumed for purposes of this analysis that operators repair all leaks on gas transmission and gas gathering lines within the year they are discovered.

PHMSA estimated the leak incidence rate empirically based on the average natural gas leaks per mile-year reported between 2015 and 2020 in PHMSA's Gas Transmission and Gathering Pipeline Annual Report: 0.0253 leaks/mile-year for gas gathering lines, and 0.0046 leaks/mile-year for gas transmission lines.[35] These rates reflect the leaks operators are detecting and reporting to PHMSA in the baseline. PHMSA understands that current leak detection practices do miss some existing leaks that could be picked up by surveys using more advanced technologies and better practices. For the analysis, PHMSA assumed that the baseline leak incidence rate reflects 85 percent of the leaks that would be detected using more advanced survey methods, based on a longstanding estimate for walking survey effectiveness (EPA, 1996). In other words, the baseline corresponds to 85 percent relative effectiveness (where "relative effectiveness" is effectiveness relative to what is achievable using ALD techniques and equipment meeting the specified performance criteria of the proposed rule).[36] PHMSA believes this estimate of incremental relative effectiveness to be a conservative estimate of the improvements that can be expected as a result of using ALD techniques and equipment, but the relative effectiveness of baseline leak detection practices is uncertain and could be lower. Given the influence of this parameter on the estimation of costs and benefits for the proposed rule and the potentially systemic underestimation of leak incidence across the pipeline industry, especially for gas gathering pipelines (as discussed in sections 3.3 and 6.2), PHMSA also conducted a sensitivity analysis that assumes a greater difference (50 percent relative effectiveness) between practices used in the baseline and under the proposed rule (*i.e.*, assuming that baseline practices are actually only detecting 50 percent of the leaks that would be detected using ALD techniques and equipment). See section 6.3 for the results of this sensitivity analysis.

As a result of more effective surveys and specified deadlines for making repairs, there are incremental costs associated with the repair of additional leaks detected under the proposed rule compared to the baseline. PHMSA applied the leak incidence rates for transmission and gathering lines uniformly for each segment irrespective of the pipeline location, diameter, or other characteristics.[37] PHMSA welcomes comments on the effectiveness of different leak detection methods in finding existing leaks in part 192-regulated gathering and transmission pipelines, including empirical data and studies comparing the effectiveness of baseline practices

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35 Section 6.2 presents alternative estimates for gathering lines derived from field surveys in the Permian Basin oil and gas production area.

36 Leak surveys conducted in compliance with the proposed performance criteria would therefore correspond to 100 percent "relative effectiveness."

37 While the data used to derive leak incidence rates are based on gathering lines regulated as of 2020 (*i.e.*, Type A and Type B), PHMSA did not find data indicating that the incidence rate for regulated Type C gathering lines is materially different. Using data for Type A and B gathering lines is reasonable given similarities in function, requirements, and operational characteristics.

with that of leak surveys using ALD techniques. PHMSA also welcomes comments and data on elapsed time between leak discovery and repairs on gas transmission and gas gathering lines.

The average unit repair cost used in the analysis for leaks on gas gathering and gas transmission lines ($5,650/leak) is based on information supporting utility rate cases for transmission services (Pacific Gas and Electric Company, 2019b).[38] PHMSA assumed that these costs include immediate post-repair leak evaluation to confirm that the repair was effective, as well as any associated recordkeeping. PHMSA further assumed that the repair costs are the same across line types and transported commodities. This is reasonable given the similarities in operational characteristics and environments traversed by the pipelines. These are average repair costs. PHMSA understands that the costs of individual repairs may vary widely depending on the nature of the leak, pipe diameter, location, type of repair needed, etc. and that some repairs may cost multiples of this average.

The proposed rule requires operators to conduct a follow-up inspection to confirm the effectiveness of the repair. PHMSA does not have information on how many operators may already be conducting post-repair follow-up inspections in the baseline and therefore assumed that all operators would incur incremental costs for this requirement. PHMSA estimated the average incremental cost of this activity for gas transmission and gathering pipelines at $218 per leak based on 4 hours of a technician's time, *i.e.*, two hours to mobilize/demobilize and travel to the location, and two hours to conduct the measurements needed to confirm the repair and document the activity (PHMSA BPJ; see details in Appendix A).[39] Accordingly, the total average unit cost for each repair to regulated gas gathering and transmission pipelines is $5,868/leak. PHMSA welcomes feedback and data on the reasonableness of these costs and on practices implemented by gathering and transmission line operators in the baseline.

Table 14 summarizes the estimated changes in the number of repairs completed under the proposed rule as compared to the baseline, and the incremental costs associated with these repairs. In the baseline, PHMSA estimated between 875 and 1,231 repairs would be completed per year for gas gathering lines over the period of analysis, and between 1,393 and 1,569 repairs would be completed per year for gas transmission lines.[40] PHMSA estimated that the proposed rule will increase the number of repairs per year to between 3,214 and 4,075 for gas gathering and between 1,639 and 1,846 for gas transmission lines.[41] The significant increase in the number of repairs projected for gas gathering lines is largely attributable to leaks detected on the subset

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38 PHMSA adjusted the unit costs reported in the rate case from 2019 dollars ($5,586) to 2020 dollars using the GDP implicit price deflator (1.012).

39 For comparison, rate cases from PG&E show unit costs for leak rechecks at $253 per leak (adjusted from the original cost of $249 per leak in 2019 dollars using the GDP deflator) (Pacific Gas and Electric Company, 2019b).

40 The leaks repaired figures in Table 14 are calculated by subtracting baseline leak repairs from proposed rule leak repairs to obtain the incremental leaks repaired under the proposed rule. For example, for transmission leak repairs, 1,393 (baseline leak repairs) is subtracted from 1,639 (proposed rule leak repairs) to get the number of incremental leaks repaired in the transmission column.

41 Independent rounding may result in small differences between these values and incremental number of repaired leaks summarized in Table 14.

of regulated Type C gathering lines that PHMSA assumed are not surveyed in the baseline but will be surveyed under the proposed rule.

Table 14: Incremental leaks and repair costs over period of analysis					
Year		Leaks repaired		Repair costs[1] (million 2020$)	
		Gathering	Transmission	Gathering	Transmission
2024		2,340	246	$14	$1.4
2025		2,372	248	$14	$1.5
2026		2,406	250	$14	$1.5
2027		2,440	252	$14	$1.5
2028		2,474	254	$15	$1.5
2029		2,509	256	$15	$1.5
2030		2,544	259	$15	$1.5
2031		2,580	261	$15	$1.5
2032		2,617	263	$15	$1.5
2033		2,653	265	$16	$1.6
2034		2,691	268	$16	$1.6
2035		2,728	270	$16	$1.6
2036		2,767	272	$16	$1.6
2037		2,805	275	$16	$1.6
2038		2,845	277	$17	$1.6
Total		**38,771**	**3,915**		
Annual average		**2,585**	**261**		
3%	**Total PV**			**$185**	**$18.7**
	Annualized			**$15**	**$1.5**
7%	**Total PV**			**$145**	**$14.8**
	Annualized			**$15**	**$1.5**
[1] Includes the cost of post-repair inspection. *Source: PHMSA analysis*					

4.1.4 National Pipeline Mapping System

The NPMS is a geographic information system (GIS) that contains the locations and attribute data for a variety of pipeline infrastructure. PHMSA is proposing to expand the scope of the NPMS by requiring operators of part 192-regulated gathering pipelines to submit appropriately formatted geospatial data, the name and address of the person with primary operational control (*i.e.*, operator), and a means for a member of the public to contact the operator for additional information about the pipeline facilities it operates. Transmission pipelines are already subject to NPMS reporting and PHMSA proposes no change for these lines. Similarly, no changes are proposed for distribution pipelines; they will remain not subject to NPMS requirements.

Under the proposed rule, operators will be required to compile and submit geospatial data about the location and selected attributes of their part 192-regulated gathering pipelines (see Table 15 below for a list of required attributes). Many of the proposed required pipeline attributes determine the applicability of regulations to specific pipelines and are therefore expected to be known to the operator (*e.g.*, type, diameter, commodity, status, interstate/intrastate, class location, onshore/offshore), but may need to be compiled in a compatible format for submission to PHMSA. Other attributes, such as the positional accuracy may need to be confirmed in the field. The incremental burden and cost of this proposed requirement depends on existing practices, notably whether operators currently use GIS software to store pipeline geospatial data and attributes to be reported to NPMS.

- Operators with both gathering and transmission pipelines likely already use GIS since transmission pipelines are subject to NPMS reporting. For this analysis, PHMSA assumed that these operators may need to modify their existing GIS to document the requested information about gathering pipelines and format the data for NPMS reporting. The 2020 Gas Gathering and Transmission Annual Report shows a total of 378 operators with part 192-regulated gathering lines; 168 operators have both transmission and part 192-regulated gathering lines (PHMSA, 2021a). The remaining 210 operators have part 192-regulated gathering lines only.
- Some operators with only part 192-regulated gathering pipelines may already use GIS software to manage pipeline data given that this is a common data management practice for geographically distributed assets and some states require the submission of GIS shapefiles as part of the permitting process. For example, the Texas Railroad Commission (RRC) requires both regulated and unregulated gathering pipeline operators to submit GIS maps to obtain their T-4 permits. The T-4 permits must be renewed annually and apply to even small diameter gathering lines in Class 1 locations. Almost all the attributes PHMSA is proposing for NPMS submittals must be included in the digital shapefiles the RRC requires with T-4 permits.[42] Kentucky has similar requirements, as part of the permitting process, for operators to provide a map showing the location and attributes of gathering lines. Nonetheless, operators with existing GIS may need to modify their data management system to enable NPMS reporting. For this analysis, PHMSA assumed that 50 percent of gathering-only operators fall into this category, or 105 operators (50 percent of 210). This estimate was informed by the 2020 Gas Gathering and Transmission Annual Report data which show that approximately 43 percent of operators with regulated Type A and Type B gathering lines are in Texas, and therefore should already have GIS and digital shapefiles of their lines; some gathering only operators in other states are also likely to use GIS to manage their assets. For these reasons, the assumption that 50 percent of operators already have GIS software and data is likely low, and costs for new GIS systems may be overestimated.
- PHMSA assumed that the remaining operators (*i.e.*, 50 percent of the 210 operators with only part 192-regulated gathering pipelines) do not already use GIS and will have to stand up a new system or acquire geospatial data management services from a vendor to enable NPMS reporting. PHMSA conservatively assumed that a total of 105 operators fall in this category.

PHMSA estimated the average upfront costs for setting up a new GIS system to collect the geospatial data and enable NPMS reporting at $10,000 for software licenses and equipment, plus 300 hours of personnel time. For operators with existing GIS, PHMSA estimated that modifying the systems to enable NPMS reporting will take an average of 60 hours. PHMSA assumed that operators will collect missing geospatial data as they conduct leak surveys discussed in Section 4.1.2.

PHMSA estimated the burden of extracting and submitting the data to PHMSA at 24 hours per operator, based on prior estimates included in the 2019 Information Collection Request (ICR)

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42 RRC requires information about pipe diameter, commodity (which also includes whether the pipeline is onshore or offshore), interstate/intrastate, pipeline status (under Texas regulations), positional accuracy, and class location. See https://www.rrc.texas.gov/media/ydkapdub/a_guide_to_shapefile_submissions.pdf for details.

supporting statement (PHMSA, 2019). See Table 15 for details. In the ICR, PHMSA further estimated that collecting data about positional accuracy will require an average of 525 hours per operator, based on estimates PHMSA developed for operators with less than 500 miles of pipelines. PHMSA further assumed that operators would have seven years from the effective date of the rule to submit data on the positional accuracy of their center lines and distributed the total effort over these seven years, for an average of 75 hours per year.

PHMSA previously estimated that subsequent annual NPMS data updates require an average of 2 minutes per mile (PHMSA, 2017); this analysis assumed the same burden for part 192-regulated gathering lines. PHMSA estimated labor costs based on the weighted-average loaded labor costs for selected occupations in the natural gas gathering industry of $91.83 per hour (Table 16).

Table 15: Regulated gas gathering reporting burden for initial NPMS reporting

Pipeline attribute	Unit burden[1] (hour/operator)
Pipe type (A, B, C)	2.5
Pipe diameter	4.0
Commodity	2.5
Interstate/intrastate	2.5
Pipeline status	2.5
Pipe material	2.5
Onshore/offshore	2.5
Class location	2.5
Revision code	2.5
Total burden per operator	**24.0**

[1] Based on unit burden from 2019 ICR supporting statement. Does not include the additional burden of collecting and submitting data on the positional accuracy of the pipeline center lines, which is estimated to average a total of 525 hours per operator.
Source: PHMSA, 2019

Table 16: Estimated unit labor cost for gas gathering reporting requirements

Occupation Code	Occupation Category	Hourly wage rate[1] (2019$/hour)	Total labor cost[2] (2020$/hour)	Estimated % of reporting burden
13-1040	Compliance Officers	$41.41	$61.55	40%
23-1010	Lawyers and Judicial Law Clerks	$91.36	$135.80	20%
17-2000	Engineers	$69.68	$103.57	20%
11-0000	Management Occupations	$78.10	$116.09	10%
15-1240	Database Administrators	$51.96	$77.23	10%
		Weighted average	**$91.83**	100%

[1] Reflects hourly wages for the listed occupations in NAICS 211100 (oil and gas extraction)
[2] Adjusts the hourly wage rates to 2020 dollars using the employment cost index (ECI) (1.03) and scales them to total labor costs based on employer cost data for the trade, transportation, and utilities sectors indicating that wages represent 69.2% of total compensation.
Source: Bureau of Labor Statistics, 2020, 2021b, 2021c

Table 17 summarizes the incremental costs of expanding NPMS reporting to part 192-regulated gas gathering. The annualized costs are $1.68 million and $1.86 million at 3- and 7-percent discount rates, respectively, or $4,431 and $4,909 per regulated gas gathering operator (378 operators).[43]

Table 17: Incremental annualized costs of NPMS reporting for regulated gas gathering							
Activity and applicability	**Costing assumptions**			**Total Costs[1] (Million 2020$)**		**Annualized cost[2] (Million 2020$)**	
	Count	**Burden[3] (hours)**	**Capital ($)**	**Upfront Costs**	**Recurring costs**	**3%**	**7%**
Set up new GIS: 50% of 210 operators with gathering only	105 operators	300	$10,000	$2.4	$0	$0.20	$0.25
Modify existing GIS: 168 operators with transmission + 50% of 210 operators with gathering only	273 operators	60	$0	$1.3	$0	$0.10	$0.13
Submit geospatial data to NPMS (first year): all operators with gathering; burden detailed in Table 15	378 operators	24	$0	$0.9	$0	$0.05	$0.07
Submit data about positional accuracy (first seven reporting years only)	378 operators	75	$0	$2.2 (x 7 years)	$0	$1.17	$1.36
Provide annual NPMS data updates (subsequent years): all operators, based on part 192-regulated gathering mileage	102,641 miles	0.033	$0	$0	$0.3	$0.22	$0.21
			Total[4]	**$19.5**	**$0.3**	**$1.68**	**$1.86**

[1] Total costs equal the number of operators or pipeline miles times the burden hours, plus capital costs.
[2] Total costs are annualized over the 15-year analysis period and reflect the timing of the activities. Upfront GIS costs are assumed to occur in 2024, the first reporting year in 2025, and subsequent data updates in 2026-2038.
[3] Activity counts and unit burdens for upfront costs are based on the number of operators, whereas recurring costs for NPMS data are based on mileage (*i.e.*, costs are total mileage × 2 minutes per mile
[4] Total may not add up due to independent rounding and different timing of the reporting activities.
Source: PHMSA analysis

4.1.5 Other Reporting and Recordkeeping

The proposed rule includes several other requirements that have the potential to increase reporting and recordkeeping activities for transmission and gathering operators. These include:[44]

- Developing or revising procedural manuals for operations, maintenance, and emergencies (§192.605)
- For Type B gas gathering operators only, emergency planning requirements (§192.615)

43 PHMSA also estimated the costs of the NPMS requirements for an additional 1,591 operators that may be associated with Type C gathering lines based on the assumption that 80 percent of the Type C gathering lines mileage is operated by different entities. Including this additional universe of operators, annualized costs increase by $6.6 million using a 3 percent discount ($7.6 million using a 7 percent discount).

44 Transmission and gathering operators are not expected to request extensions of the leak remediation time interval requirements for individual leaks under §192.760(h) since the extensions may only be granted for grade 3 leaks which inherently pose lower risks to public safety and the environment.

- Developing written procedures for grading and repairing leaks (§192.760(a)(1))
- Documenting post-repair evaluation (§192.760(e))
- Recording the history of each leak, including leak discovery, grading, monitoring, remediation, upgrades, and downgrades, and maintaining these records for a period of 5 years (records of repairs must be maintained for the life of the pipeline) (§192.760(i)(1)-(2))
- Documenting the leak detection equipment choice analysis (§192.763(f))
- Submitting requests to PHMSA for alternative performance standards for transmission and gathering lines in Class 1 and Class 2 locations (§192.763(g))
- Recording leak detection equipment calibration (and re-calibration) and maintaining these records for the life of the equipment (§192.763(h)(2))
- Recording repair or replacement of a pressure relief device and maintaining these records for the life of the pipeline (§192.773(c))

In addition, PHMSA is revising Part M of the Transmission and Gathering Annual Report form to require operators to submit additional information about the number of leaks discovered and repaired by grade. The additional information includes summaries of leaks discovered, repaired, and outstanding, by grade, as well as estimates of methane emissions. Much of this information is already collected by operators as part of their leak and integrity management programs but will need to be compiled for submission as part of the annual report. PHMSA estimated that the requirement to report additional information may add 10 hours in the first year and 5 hours in subsequent years to the approved reporting burden for annual reports. The estimated increase in ongoing burden represents approximately 1/10th of the approved per respondent burden for existing annual reports (PHMSA, 2021d). The higher first-year burden accounts for the additional time operators may need to modify existing reporting procedures.[45]

Costs for leak surveys, repairs (including post-repair evaluations), and monitoring are assumed to include the documentation of these activities in accordance with company practices. PHMSA believes operators already document these activities; otherwise, they would not be able to run their leak survey and repair programs. Some of these records — for example, repair records — are already required under various regulations; others are necessary for the proper operation of the pipeline systems and implementation of integrity management plans. Similarly, proper operation and maintenance of leak survey equipment is included in the survey unit costs. This includes recalibration of leak detection equipment upon malfunction indication, consistent with equipment manufacturer recommendations.

PHMSA proposes to extend the requirement under §192.605 to prepare and follow a written procedure manual for operations, maintenance, and emergency response activities to Type B and Type C gathering lines. The requirements currently apply to onshore or offshore gas transmission

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45 In the Supporting Statement for "Annual and Incident Reports for Gas Pipeline Operators" OMB Control No. 2137-0522 (Docket No. PHMSA-2011-0023) PHMSA estimated the unit burden for completion and submittal of a Gas Transmission and Gathering Annual Report (form F7 100.2-1) at 47 hours per respondent. See https://www.reginfo.gov/public/do/PRAViewDocument?ref_nbr=202111-2137-002 for details (PHMSA, 2021d).

pipelines, gas distribution pipelines, offshore gas gathering pipelines, and Type A gas gathering pipelines. Similarly, PHMSA proposes to extend the emergency planning requirements at §192.615 to Type B gas gathering pipelines. For this analysis, PHMSA expects that operators with pipelines already covered by an existing procedure manual already implement applicable procedures across their pipeline network. The number of operators incurring the burden associated with this change include the 63 operators that reported Type B gathering lines only in 2020 (*i.e.*, did not also operate gas transmission, Type A gas gathering, or offshore gas gathering pipelines), as well as operators estimated to operate Type C gathering lines only. For the second category, PHMSA assumed that Type C gathering lines are operated by the same entities that operate Type A and Type B gathering lines.[46] As noted in Section 3.1.3, there is uncertainty on the number of operators associated with Type C gathering lines since they have not been required to report to PHMSA until recently. PHMSA plans to update this assumption when operators submit their annual reports for 2022 but to address the uncertainty, PHMSA also conducted a sensitivity analysis that assumes that 80 percent of the Type C gathering lines mileage is operated by different entities, adding an estimated 1,591 operators. PHMSA estimated that development of written procedure manual will require 100 hours per operator, assuming a similar level of effort as previously estimated for the development of management of change procedures for gas transmission pipelines.[47]

PHMSA estimated that 64 operators have Type B gathering lines only and therefore may need to develop emergency plan as a result of the proposed extension of the requirements at 192.615 to these lines. PHMSA estimated the upfront cost of developing an emergency plan at $5,000 and the subsequent annual cost of maintaining the plan at $750 (PHMSA, 2021c).[48] Operators with other types of gas pipelines already have an existing emergency plan in the baseline and PHMSA assumes no incremental costs for updating their existing plan, if needed, as part of ongoing maintenance of the plan.

PHMSA expects that all regulated gas gathering and gas transmission system operators currently have a written procedure for grading and repairing leaks, but will need to revise their existing procedure to comply with the proposed rule requirements. PHMSA also assumed that all operators of onshore gas gathering and transmission pipelines will need to document the analysis supporting the selection of leak detection equipment meeting performance requirements in the proposed rule. PHMSA assumed 61.5 hours and 23 hours, respectively, for developing or

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46 As noted in the RIA for the Expansion of Gas Gathering Regulation, PHMSA estimated that 97 percent of the mileage of newly regulated Type C gas gathering pipelines is attributable to operators with previously regulated pipelines (PHMSA, 2021c).

47 The burden estimates are informed by prior estimates PHMSA detailed in the RIA for the "Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments," for the development of operator plans detailing procedures for Management of Change (maximum of 100 hours) (PHMSA, 2022).

48 These figures were taken from the 2021 Gas Gathering Final Rule RIA which can be found at https://www.regulations.gov/document/PHMSA-2011-0023-0488.

updating these documents.[49] Each operator performs these activities once at the start of the period of analysis.

The installation of appropriately sized pressure relief devices, verification of their correct functioning, and repair or replacement as needed, are already standard practice under the baseline and hence PHMSA assumed no cost associated with these repairs or replacements attributed to this rule. The only change under the proposed rule is the requirement to document such activities. However, operators are already expected to keep these records as part of their existing maintenance procedures and the proposed rule therefore mostly clarifies this expectation. Since the proposed rule does not require the records to be kept in a specific format, PHMSA expects no changes to the baseline recordkeeping procedures currently used by operators, and therefore no incremental costs. PHMSA welcomes such data or feedback on whether this is reasonable across the set of operators covered by the requirements.

All part 192-regulated gas gathering and gas transmission operators are already required to submit incident and annual reports to PHMSA and should therefore have the processes, procedures, forms, and training to readily extend their current reporting, but the actual reporting could result in additional costs. New reporting requirements for unintentional releases between 1 and 3 MMcf will result in additional reports submitted to PHMSA each year. PHMSA does not have information on the current number of leaks between 1 and 3 MMcf. For the purpose of this analysis, PHMSA assumed that 7 percent of leaks on gas gathering lines and 8 percent of leaks on gas transmission lines would be subject to these reporting requirements, based on gathering and transmission incident reports of unintentional releases of natural gas between 1 and 3 MMcf (PHMSA, 2021b). Therefore, gas gathering and gas transmission operators would submit a total of 393 reports on average each year (254 and 139 reports for gathering and transmission, respectively),[50,51] with each report estimated to require 12 hours[52] to prepare.

PHMSA estimated that additional information to be reported in the Natural and Other Gas Transmission and Gathering Pipeline Systems annual report form (PHMSA Form F7100.2-1) will add approximately 6 hours to the existing burden.[53] This estimate is based on PHMSA's

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49 The burden estimates are informed by prior estimates PHMSA detailed in the RIA for the "Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments," for the development of operator plans detailing procedures for Management of Change (average of 61.5 hours) and for updating existing procedures for inspections following extreme weather events (average of 23 hours) (PHMSA, 2022).

50 The 254 reports for gas gathering represent 7 percent of the average estimated total of 3,631 leaks and the 139 reports for gas transmission represent 8 percent of the average estimated total of 1,740 leaks.

51 For context, PHMSA has received an average of 122 incidents per year from part 192-regulated gathering (Type A and B) and transmission pipeline operators during the period of 2010-2020.

52 The burden estimate is informed by prior estimates PHMSA detailed in the RIA for the "Pipeline Safety: Expansion of Gas Gathering Regulation Final Rule," for the preparation and submittal of incident reports for newly regulated gas gathering pipelines (PHMSA, 2021c) and PHMSA's estimated reporting burden in the associated information collection request.

53 For context, the existing average annual burden for part 192-regulated gathering and transmission pipelines is estimated to be 21.5 hours, as detailed in reporting and recordkeeping cost estimates for newly regulated gas gathering pipelines ($1,875 per year; or 21.5 hours at the average wage rate used of $86.81) (PHMSA, 2021c).

expectation that operators already track this type of information in the baseline as part of managing their pipeline system but may need additional time to compile it for their annual report. Each operator submits one report per year.

PHMSA estimated costs based on the assumed hour burdens and weighted-average loaded labor costs for selected occupations in the natural gas gathering industry of $91.83 per hour (Table 16) and natural gas transmission industry of $76.63 (Table 18).

PHMSA welcomes data and comments on the estimated burden and associated labor costs for the additional reporting and recordkeeping activities resulting from the proposed rule, and on the baseline reporting and recordkeeping practices already implemented by part 192-regulated gas gathering and transmission operators.

Table 18: Estimated unit labor cost for gas transmission reporting requirements

Occupation Code	Occupation category	Hourly wage rate[1] (2019$/hour)	Total labor cost[2] (2020$/hour)	Estimated % of reporting burden
13-1040	Compliance Officers	$40.72	$60.53	40%
23-1010	Lawyers and Judicial Law Clerks	$70.84	$105.30	20%
17-2000	Engineers	$51.80	$77.00	20%
11-0000	Management Occupations	$63.75	$94.76	10%
15-1240	Database Administrators	$43.65	$64.88	10%
		Weighted average	**$76.63**	100%

[1] Reflects hourly wages for the listed occupations in NAICS 486200 (pipeline transportation of oil and gas)
[2] Adjusts the hourly wage rates to 2020 dollars using the employment cost index (ECI) (1.03) and scales them to total labor costs based on employer cost data for the trade, transportation, and utilities sectors indicating that wages represent 69.2% of total compensation.
Source: Bureau of Labor Statistics, 2020, 2021b, 2021c

Table 19 and Table 20 present PHMSA's estimates of the total annualized costs for gas gathering and gas transmission, respectively, associated with reporting and recordkeeping activities not already included in the surveys, repair, and monitoring costs. The cost of each activity was calculated based on the count of activities times the burden hours times the weighted average total labor cost. This cost was assumed to recur at the frequency indicated by the life, *i.e.*, either once during the period of analysis or each year or each event. For operators with both gas transmission and gathering pipelines, PHMSA assumed that recording and recordkeeping activities will be consolidated; to avoid double-counting, PHMSA accounted for the associated costs as part of the transmission segment estimates in Table 20.

The total annualized costs for other reporting and recordkeeping are $1.8 million and $2.0 million at 3- and 7-percent discount rates, respectively (average of $1,349 and $1,496 per operator per year based on a total of 1,308 operators with gas gathering and/or gas transmission pipelines).[54]

As discussed above, the number of operators associated with Type C gathering lines is uncertain since these operators have not yet submitted annual reports. Using alternative assumptions wherein an additional 1,591 operators are subject to reporting and recordkeeping requirements

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54 The total costs may not add up to the sum of values presented in Table 19 and Table 20 due to independent rounding.

for Type C gathering lines would add approximately $2.6 million per year to the estimates in Table 19.

Table 19: Incremental annualized costs of part 192-regulated gas gathering system reporting and recordkeeping requirements

Requirement	Costing assumptions			Annualized cost (Million 2020$)[1]	
	Count[2]	Burden (hours)	Life (years)	3%	7%
Written procedures for operations, maintenance, and emergency response	63	100.0	15	<$0.1	$0.1
Written procedures for grading and repairing leaks	209	61.5	15	$0.1	$0.1
Emergency plan for Type B lines[3]	64			$0.1	$0.1
Leak detection equipment choice analysis	84	23.0	15	$0.0	$0.0
Report of incidents involving large volume releases of gas	254	12.0	1	$0.3	$0.3
Additional reporting of leaks in the Annual Gas Gathering and Transmission Report	209	6.0	1	$0.1	$0.1
			Total[4]	**$0.6**	**$0.7**

[1] Annualized reporting and recordkeeping costs are calculated by multiplying the count of activities *n* by the burden hours *h* and total labor costs *w* and then annualizing this cost over the life of the activities *t* using the discount rate *r* (3 percent or 7 percent), *i.e.*, $n \times h \times w \times \frac{r}{1-(1+r)^{-t}}$

[2] The count of operator-level activities (developing written procedures, leak detection equipment analysis, pressure relief device, and annual reporting of leaks) reflect operators with gas gathering pipelines only. Operators with both gas gathering and gas transmission pipelines are included in Table 20.

[3] PHMSA estimated the upfront cost of developing an emergency plan at $5,000 per operator and the subsequent annual cost of maintaining the plan at $750 per operator.

[4] Total may not add up due to independent rounding.

Source: PHMSA analysis

Table 20: Incremental annualized costs of gas transmission system reporting and recordkeeping requirements

Requirement	Costing assumptions			Annualized cost (Million 2020$)[1]	
	Count[2]	Burden (hours)	Life (years)	3%	7%
Written procedures for grading and repairing leaks	1,099	61.5	15	$0.4	$0.5
Leak detection equipment choice analysis[3]	1,096	23	15	$0.2	$0.2
Report of incidents involving large volume releases of gas	139	12.0	1	$0.1	$0.1
Additional reporting of leaks in the Annual Gas Gathering and Transmission Report	1,099	6	1	$0.5	$0.5
			Total[4]	**$1.2**	**$1.4**

[1] Annualized reporting and recordkeeping costs are calculated by multiplying the count of activities *n* by the burden hours *h* and total labor costs *w* and then annualizing this cost over the life of the activities *t* using the discount rate *r* (3 percent or 7 percent), *i.e.*, $n \times h \times w \times \frac{r}{1-(1+r)^{-t}}$

[2] The count of operator-level activities (developing written procedures, leak detection equipment analysis, pressure relief device, and annual reporting of leaks) includes operators with both gas gathering and gas transmission pipelines.

[3] Operators with onshore lines (1,096 operators) are assumed to incur this cost; three operators with only offshore lines are expected to continue using current leak detection technologies.

Table 20: Incremental annualized costs of gas transmission system reporting and recordkeeping requirements
[4] Total may not add up due to independent rounding.   *Source: PHMSA analysis*

As described in section 3.5, the proposed rule incorporates several self-implementing provisions under Section 114 of the PIPES Act of 2020 that mandate changes to inspection and maintenance plans to minimize gas releases from pipeline facilities. These provisions include developing written procedures for the elimination of all hazardous leaks and for minimizing releases of gas and documenting method(s) used to minimize the release of gas to the environment due to operational blowdowns. Because these reporting and recordkeeping requirements are mandated explicitly by the Act and will be in effect before the expected effective date of this proposed rule, PHMSA considered them to be part of the baseline and did not attribute the associated costs to the rule.

4.1.6 Gas Gathering and Gas Transmission Total Costs

Table 21 presents the total estimated costs of the proposed rule requirements for gas gathering and gas transmission, including patrolling, leakage surveys, repairs, NPMS reporting, and other reporting and recordkeeping.

Table 21: Total costs of proposed rule requirements for gas gathering and gas transmission over period of analysis (million 2020$)

Year		Gathering	Transmission
2024		$196	$21
2025		$196	$14
2026		$198	$14
2027		$201	$14
2028		$204	$14
2029		$207	$14
2030		$209	$14
2031		$212	$14
2032		$213	$14
2033		$216	$14
2034		$219	$14
2035		$223	$14
2036		$226	$14
2037		$229	$15
2038		$232	$15
3%	**Total PV**	**$2,589**	**$183**
	Annualized	**$211**	**$15**
7%	**Total PV**	**$2,034**	**$147**
	Annualized	**$209**	**$15**

Source: PHMSA analysis

4.2 Gas Distribution

4.2.1 Leakage Surveys

The proposed rule will reduce the maximum interval between required leakage surveys of gas distribution mains and services outside of business districts. Table 22 shows the intervals PHMSA assumed for different types of gas distribution mains under the baseline and proposed rule. In cases where states already have more stringent requirements in the baseline, PHMSA accounted for these requirements in the analysis and used the most stringent of the state or federal requirement for the baseline and under the proposed rule. Specifically, PHMSA accounted for more stringent survey requirements in two states: Connecticut, which requires annual surveys for all mains, and Massachusetts, which requires surveys every two years.[55]

Table 22: Gas distribution pipeline survey intervals.

Source main material	Baseline interval (years)[1]	Proposed rule interval (years)[1]
Bare Steel, Unprotected	3	1
Coated Steel, Unprotected	3	1
Bare Steel, Protected	5	3
Coated Steel, Protected	5	3
Plastic	5	3
Plastic, historic subset with known issues[2]	3	1
Cast Iron	3	1
Ductile Iron	3	1
Copper	3	1
Reconditioned Cast Iron	5	3
All Others	3	3

[1] Mains may have different survey intervals when located in states that have more stringent requirements. For example, distribution mains in Connecticut are assumed to be surveyed annually in the baseline.
[2] The proposed rule would require annual leakage surveys for historic plastics with known issues. PHMSA does not have data on the fraction of plastic mains affected by these issues and therefore did not differentiate these mains in the analysis.
Source: PHMSA analysis

For the analysis, PHMSA assumed that operators allocate survey resources uniformly across miles and over time, *i.e.*, in the case of a three-year cycle, operators survey one third of miles each year. PHMSA further assumed that operators survey both mains and connected service lines at the same time. This assumption is consistent with the unit costs PHMSA used for the analysis which are inclusive of surveys on both mains and services but are expressed on the basis of main mileage. PHMSA compiled a sample of operator-developed estimates of the total costs of surveying their gas distribution system (both mains and services), which PHMSA divided by the miles of main to estimate the unit costs for conducting surveys. PHMSA then used the average costs across operators of $1,370/mile (Southern California Gas Company, 2020; Pacific Gas and Electric Company, 2018).[56] This average unit cost reflects survey programs that combine mobile

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[55] The state of Nevada initiated a rulemaking that would require annual surveys of all mains, but the requirements had not been finalized at the time this analysis was performed.

[56] Calculated as the average of $1,245/mile ($4,332,793 to survey 3,480 miles of unprotected steel mains per year; Southern California Gas Company, 2020) and $1,490/mile ($344,208 to survey 231 miles; Pacific Gas and Electric Company, 2018).

technologies, where appropriate, with walking surveys and pinpointing of leaks. PHMSA expects these practices to meet the performance criteria specified in the proposed rule and therefore used the same unit costs under the baseline and proposed rule. PHMSA assumed that this cost includes any associated recordkeeping to document the survey and associated findings, as is already expected under baseline practices. Similarly, operators already have training programs for personnel involved in leak surveys and PHMSA assumed that any adjustment to the training is included in the cost of implementing the program. Finally, PHMSA assumed that proper operation and maintenance of leak survey equipment is included in the survey unit costs. This includes recalibration of leak detection equipment upon malfunction indication, consistent with equipment manufacturer recommendations.

PHMSA applied the unit costs to all main mileage estimated to be surveyed in any given year, *i.e.*, across operators, pipeline materials, survey methods, etc. PHMSA recognizes that leakage survey costs may differ depending on system characteristics and other variables; the average is meant to account for the variability across distribution systems.

PHMSA welcomes comments and data on leakage survey practices implemented by gas distribution operators in the baseline and any incremental costs for meeting the performance criteria specified in the proposed rule.

PHMSA assumed that ALD methods and procedures implemented under the proposed rule will increase the effectiveness of leak surveys to be on par with leak indications in Weller *et al.* (2020) and Lamb *et al.* (2015) and used leak incidence rates reported in these studies as the basis for modeling the proposed rule scenario. Several studies have demonstrated that ALD methods may identify leaks otherwise missed by traditional methods (Lamb et al., 2015; Weller et al., 2020; D. Zimmerle et al., 2020). Similar to the assumption used for gathering and transmission, in modeling the baseline scenario, PHMSA assumed that baseline practices used by distribution operators are able, on average, to detect 85 percent of the existing leaks that would be detected using ALD methods, *i.e.*, baseline practices have a relative effectiveness of 85 percent when compared to ALD methods. This is consistent with a longstanding estimate for walking surveys effectiveness (EPA, 1996). PHMSA believes this to translate into a conservative estimate of the potential improvements that can be expected as a result of using ALD techniques. Comparative data PHMSA obtained from technology vendors suggest that ALD techniques may identify more than twice the number of gradable leaks identified during traditional surveys (*i.e.*, the relative effectiveness of traditional survey practices may be only 50 percent of the effectiveness of ALD techniques).[57] At the same time, some operators already implement ALD practices in the baseline and therefore may see no effectiveness improvement under the proposed rule scenario from changing survey methods alone. Since this parameter is central to the estimation of the costs and benefits of the proposed rule, PHMSA also conducted a sensitivity analysis that assumed a greater difference (50 percent) between practices used in the baseline and under the proposed rule. Section 6.3 provides the results of this sensitivity analysis.

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[57] Based on double-blind study summary results provided by Picarro, dated May 21, 2019. Results vary across field trials, with surveys using ALD finding between 0.9 to 13 times the number of gradable leaks identified using traditional methods. Omits results where no leak was found using a traditional survey.

For analytic simplicity, PHMSA assumed uniform effectiveness of leak surveys and improvements thereof across the types of leaks modeled (*i.e.*, across commodities, grades, and emission rates), but acknowledges that actual effectiveness may vary depending on the specific survey method, leak characteristics, and environmental conditions. PHMSA welcomes data comparing the effectiveness of different leak detection methods in finding existing leaks in distribution mains and services.

PHMSA recognizes that a subset of "historic" plastic pipelines will have to be surveyed annually under the proposed rule, instead of every 3 years in the baseline. PHMSA does not have data on the affected share of historic plastic pipelines but expects this requirement will affect a relatively small fraction of the existing mileage. PHMSA understands that many operators already implement more frequent surveys on these lines and account for them in their integrity management and replacement plans (for example, see Pacific Gas and Electric Company (2019a)). For this analysis, PHMSA did not differentiate these mains. PHMSA welcomes input on the mileage of "historic" plastic mains and current leak survey practices used by operators with affected mains.

Finally, PHMSA applied the same assumptions to pipelines carrying other gas commodities. As noted in section 3.1.2, the bulk of distribution mains subject to the baseline and proposed rule requirements (99.8 percent) transport natural gas; less than 0.2 percent carry landfill gas, synthetic gas, propane, or nitrogen.

Table 23 summarizes the estimated changes in the number of miles surveyed under the proposed rule as compared to the baseline, and the incremental costs associated with conducting these surveys. These estimates reflect both the changes in survey intervals and inventory of mains over the period of analysis and account for any more stringent state requirements. Following the methodology detailed in section 2.1.5 and Appendix A, the approach entailed calculating for both the baseline and the proposed rule, the number of miles to be surveyed each year, based on the mileage of mains inside and outside business districts, miles of mains of each material, and survey interval applicable to each category and material, and multiplying this mileage by the survey costs. PHMSA then calculated differences between the two scenarios to estimate the incremental mileage and costs attributable to the proposed rule. The change in the main mileage surveyed per year (208,044 miles) represents a 55-percent increase in the mileage surveyed, when compared to an estimated average of 380,391 miles per year in the baseline.

Table 23: Incremental surveyed mileage and leakage survey costs over period of analysis

Year	Surveyed miles	Survey costs (million 2020$)
2024	201,031	$275
2025	201,737	$276
2026	202,509	$277
2027	203,389	$279
2028	204,381	$280
2029	205,393	$281
2030	206,443	$283
2031	207,508	$284
2032	208,627	$286
2033	209,820	$287
2034	211,050	$289
2035	212,450	$291

Table 23: Incremental surveyed mileage and leakage survey costs over period of analysis			
Year		Surveyed miles	Survey costs (million 2020$)
2036		213,931	$293
2037		215,436	$295
2038		216,956	$297
Total		**3,120,662**	
Annual average		**208,044**	
3%	**Total PV**		**$3,494**
	Annualized		**$284**
7%	**Total PV**		**$2,759**
	Annualized		**$283**
Source: PHMSA analysis			

The proposed rule requires operators to perform a leakage survey when freezing ground, heavy rain, flooding, or other changes to the environment occur near an existing leak that could affect the venting of gas or could cause migration of gas to the outside wall of a building. The proposed rule further requires operators to conduct a survey after extreme weather events and land movement that has the likelihood of damage to pipeline facilities. PHMSA does not have data on the frequency at which these conditions may occur. In some cases, the surveys may replace or be coordinated with scheduled surveys or required monitoring of known leaks (*e.g.*, accelerate a survey that would otherwise have occurred slightly later). PHMSA recognizes, however, that the requirement could result in additional surveys needing to be conducted, beyond changing the timing of scheduled surveys. PHMSA estimated that an additional 1 percent of pipeline main mileage may need to be surveyed each year in response to extreme weather events, resulting in annualized cost of approximately $8 million (see Table 24).

Table 24: Incremental surveyed mileage and leakage survey costs due to extreme events over period of analysis			
Year		Surveyed miles	Survey costs (million 2020$)
2024		5,545	$7.6
2025		5,589	$7.7
2026		5,633	$7.7
2027		5,680	$7.8
2028		5,728	$7.8
2029		5,777	$7.9
2030		5,826	$8.0
2031		5,875	$8.0
2032		5,926	$8.1
2033		5,977	$8.2
2034		6,030	$8.3
2035		6,085	$8.3
2036		6,141	$8.4
2037		6,198	$8.5
2038		6,255	$8.6
Total		**88,265**	
Annual average		**5,884**	
3%	**Total PV**		**$98.7**
	Annualized		**$8.0**
7%	**Total PV**		**$77.7**
	Annualized		**$8.0**
Source: PHMSA analysis			

PHMSA further assumed that 5 percent of known leaks monitored each year may require additional surveys (in addition to the scheduled monitoring) to detect potential changes in leakage rate or gas migration due to environmental conditions. PHMSA included these costs with the leak monitoring costs described in the next section.

4.2.2 Leak Repairs and Monitoring

The proposed rule sets a 6-month deadline for repairing grade 2 leaks, which include "any leak with a leakage rate of 10 CFH or more," and sets a 24-month deadline for repairing grade 3 leaks. The proposed rule would also give operators 3 years to repair all grade 3 leaks known as of the effective date of the rule.

Based on the review of performance data from distribution operators in New York and Massachusetts, PHMSA assumed that 40 percent of leaks detected in the baseline are grades 1 or 2, and 60 percent are grade 3 leaks (Boston Gas, 2021; Colonial Gas, 2021; New York Department of Public Service, 2021). For the proposed rule, PHMSA assumed that approximately 15 percent of grade 3 leaks meet the definition of grade 2 leaks based on their emission rate. This assumption corresponds to the share of leaks Massachusetts operators classified as "Environmentally Significant Grade 3 Gas Leaks" under the requirements in the Code of Massachusetts Regulations (CMR; 200 CMR 114.07).

Table 25 shows the deadline PHMSA assumed for analysis purposes for different types of leaks under the baseline and following rule promulgation. The baseline repair deadline assumptions are meant to represent averages across the industry for the purpose of this analysis, but PHMSA understands that some operators currently repair leaks sooner than implied by the table, either voluntarily or to comply with state requirements, whereas other operators may take longer to make repairs.

Some states already have more stringent requirements in the baseline and the proposed rule would not affect repairs in these states. The analysis accounts for more stringent leak repair requirements in three states: California, which specifies as best-practice a three-year deadline for repairing grade 3,[58] and Connecticut and Massachusetts, which both have regulations requiring certain grade 3 leaks with significant environmental impact (SEI) to be repaired within one year and other grade 3 leaks to be repaired within 2 years. PHMSA found that operators already repair a share of grade 3 leaks within the year when they are discovered. For this analysis, PHMSA used 10 percent as the fraction of grade 3 leaks repaired in the year they are discovered in the baseline. This is based on review of performance reports submitted by certain utilities to the public utility commission, as well as statements by local distribution companies (Boston Gas, 2021; Colonial Gas, 2021).

Average elapsed times between discovery and repair of grade 3 leaks (SEI and non-SEI) in calendar year 2020 were 2.4, 3.2 and 5.0 years, respectively for Eversource, Boston Gas, and Colonial Gas (Boston Gas, 2021; Colonial Gas, 2021; Eversource Energy, 2021). CPUC and California Air Resources Board (CARB) reported a weighted average of 2.2 years (818 days) to

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[58] See BP21 in "Natural Gas Leakage Abatement Summary of Best Practices Working Group Activities And Revised Staff Recommendations" (CPUC, 2017)

repair grade 3 leaks in 2020 for California distribution utilities (CPUC and CARB, 2022). Some leaks were older, however, and PHMSA used 5 years as the baseline assumption of the time to repair grade 3 leaks. There is evidence that operators implement best practices such as those recommended by CPUC, and that this is not limited to large operators. For example SoCal Gas reported an inventory of 32 months for "non-hazardous" grade 3 leaks, and a goal of reducing the repair timeframe for these leaks to 24 months (Southern California Gas Company, 2021). Southwest Gas implements a 3-year repair cycle for grade 3 leaks (CPUC and CARB, 2020). Alpine, a small distribution company,[59] noted in 2018 their policy to repair all grades 2 and 3 leaks upon discovery, and where conditions do not allow for prompt repair, to monitor and repair grade 2 within six months and grade 3 within 15 months (Alpine Natural Gas Operating Company, 2018).

PHMSA further assumed that when needed, operators make any necessary repairs to services associated with the mains at the same time.

Table 25: Gas distribution main leak repairs

Leak category	Baseline repair deadline (years) [1,2]	Proposed rule repair deadline (years)
Grade 1	0 (Immediate)	0 (Immediate)
Grade 2	0 (6 months)	0 (6 months)
Grade 3 (baseline) / Grade 2 (proposed)	3	0 (6 months)[3]
Grade 3, others	5	2
Grade 3, existing before the effective date of the rule	N/A	3

[1] Mains may have different repair deadlines depending on the state. For example, in Connecticut SEI grade 3 leaks must be repaired within 12 months.
[2] PHMSA assumed that 10 percent of grade 3 leaks are repaired within the year they are discovered in the baseline, based on operator data. See 0.
[3] PHMSA assumed that leaks in this category have a leak rate of 10 CFH or greater and therefore meet the proposed criteria for grade 2 leaks needing to be repaired within 6 months of discovery.
Source: PHMSA analysis; reflects proposed rule requirements

PHMSA used an average unit repair cost ($4,300/leak) that reflects a broad range of conditions and is based on rate cases and other documents filed with state agencies (National Grid, 2020; Pacific Gas and Electric Company, 2020b; Southern California Gas Company, 2020). Based on the description of the practices in the source documents, PHMSA assumed that these costs include immediate post-repair leak evaluation to confirm that the repair was effective, as well as any associated recordkeeping, as these activities are not broken out separately in the source documents. The proposed rule also requires operators to conduct a follow-up inspection to confirm the effectiveness of the repair. PHMSA understands that not all operators may be conducting such follow-up inspections in the baseline and this proposed requirement may therefore represent incremental costs for the operators. PHMSA estimated the incremental cost of this activity, beyond the cost of the repair, at $109 per leak. This is based on 2 hours of a technician's time, *i.e.*, one hour to mobilize/demobilize and travel to the location, and one hour to conduct the measurements needed to confirm the repair and document the activity (PHMSA BPJ; see details in Appendix A). Accordingly, the total unit cost for each repair, including

59 Alpine served 27 commercial-retail customers and 1,575 residential customers in 2018 (Alpine Natural Gas Operating Company, 2018).

follow-up inspections is $4,409/leak. PHMSA welcomes feedback and data on the reasonableness of these average unit costs.

Following the methodology detailed in Appendix A, each detected leak is scheduled for repair according to the applicable deadlines for each grade under the analyzed scenario (baseline or proposed rule). For each year and analysis scenario (*i.e.*, baseline and proposed rule, leak incidence rates based on Lamb *et al.* (2015) and Weller *et al.* (2020) as discussed in section 3.2), PHMSA summed the number of leaks to be repaired in that year and multiplied this number by the unit repair costs. PHMSA then calculated the difference between the baseline and proposed rule to obtain the incremental number of repairs and repair costs attributable to the proposed rule.

While the assumed repair costs are based on data for natural gas distribution pipelines, PHMSA applied the same assumptions to distribution pipelines carrying other gas commodities (landfill gas, synthetic gas, propane, or nitrogen). As discussed in section 3.1.2, these other commodities represent a very small share (0.2 percent) of the total mileage analyzed.

Table 26 summarizes the estimated changes in the number of repairs completed under the proposed rule as compared to the baseline, and the incremental costs associated with these repairs. These estimates are presented as a range since they depend on the assumed leak incidence rate. Incremental costs attributable to the proposed rule arise from more effective detection of grades 1, 2, and 3 leaks and the accelerated detection and subsequent repairs of leaks, particularly those leaks classified as grade 3 in the baseline and grades 2 or 3 under the proposed rule.

As shown in Table 26, PHMSA's model projects a spike in the number of leaks repaired in early years of the analysis as operators address their backlog of existing leaks.

Table 26: Incremental leaks and repair costs over period of analysis

Year		Leaks repaired		Repair costs[1] (million 2020$)	
		Lamb *et al.* (2015)	Weller *et al.* (2020)	Lamb *et al.* (2015)	Weller *et al.* (2020)
2024		67,296	78,710	$297	$347
2025		64,751	78,428	$285	$346
2026		107,001	184,199	$472	$812
2027		96,214	170,508	$424	$752
2028		58,865	126,059	$260	$556
2029		34,769	75,457	$153	$333
2030		29,496	43,648	$130	$192
2031		28,796	43,826	$127	$193
2032		28,098	44,003	$124	$194
2033		27,387	44,176	$121	$195
2034		26,738	44,365	$118	$196
2035		26,230	44,594	$116	$197
2036		25,791	44,844	$114	$198
2037		25,500	45,143	$112	$199
2038		25,238	45,448	$111	$200
Total		**672,169**	**1,113,407**		
Annual average		**44,811**	**74,227**		
3%	**Total PV**			**$2,573**	**$4,232**
	Annualized			**$209**	**$344**
7%	**Total PV**			**$2,188**	**$3,563**
	Annualized			**$224**	**$366**

Table 26: Incremental leaks and repair costs over period of analysis				
Year	Leaks repaired		Repair costs[1] (million 2020$)	
	Lamb *et al.* (2015)	Weller *et al.* (2020)	Lamb *et al.* (2015)	Weller *et al.* (2020)
[1] Includes the cost of post-repair inspection. *Source: PHMSA analysis*				

Operators must monitor known leaks until repairs are completed. For leaks classified as grade 3, the proposed rule would require that operators monitor the leaks every six months (*i.e.*, twice a year); this is compared to an assumed baseline monitoring frequency of once a year based on the GPTC guide (GPTC, 2018). Following the methodology described in section 2.1.5 and detailed in Appendix A, PHMSA estimated the number of grade 3 leaks discovered but not yet repaired as of that year, and multiplied this number by the unit monitoring cost per year. PHMSA estimated the incremental unit monitoring cost at $109 per leak per year, based on 2 hours of a technician's time, *i.e.*, one hour to mobilize/demobilize and travel to the location, and one hour to conduct the measurements needed to confirm the repair and document the activity (PHMSA BPJ; see details in Appendix A). This unit monitoring cost accounts for the frequency of monitoring, which is once per year in the baseline and every six months under the proposed rule. PHMSA performed these calculations for each scenario and then calculated the changes attributable to the proposed rule as the differences between the baseline and proposed rule. For the proposed rule, the calculations included additional monitoring events for 5 percent of known leaks to illustrate the potential for incremental costs associated with requirements to conduct surveys following conditions that could change the leakage rate or cause gas to migrate (see section 4.2.1).

Table 27 summarizes the estimated changes in the number of monitored leaks under the proposed rule as compared to the baseline, and the incremental monitoring costs. PHMSA estimated that the number of leaks monitored would decrease after an initial transition period as operators repair leaks and reduce their backlog, but that monitoring costs would increase because of the requirement to monitor leaks more frequently until repaired (*e.g.*, twice a year vs. once a year).

Table 27: Incremental leak monitoring costs over period of analysis				
Year	Leaks monitored		Monitoring costs[1] (million 2020$)	
	Lamb *et al.* (2015)	Weller *et al.* (2020)	Lamb *et al.* (2015)	Weller *et al.* (2020)
2024	0	0	$8.3	$16.3
2025	47,732	47,638	$22.9	$35.1
2026	94,370	95,639	$36.2	$52.3
2027	31,467	22,417	$24.3	$41.8
2028	-21,542	-36,287	$11.7	$28.7
2029	-48,101	-120,196	$5.2	$9.7
2030	-51,427	-153,369	$4.1	$2.4
2031	-50,309	-154,588	$4.0	$2.4
2032	-49,307	-155,839	$3.9	$2.4
2033	-48,379	-157,110	$3.8	$2.3
2034	-47,454	-158,383	$3.7	$2.3
2035	-46,556	-159,663	$3.6	$2.3
2036	-45,671	-160,942	$3.5	$2.3
2037	-44,795	-162,221	$3.5	$2.3
2038	-44,058	-163,543	$3.5	$2.3

Table 27: Incremental leak monitoring costs over period of analysis					
Year		Leaks monitored		Monitoring costs[1] (million 2020$)	
		Lamb *et al.* (2015)	Weller *et al.* (2020)	Lamb *et al.* (2015)	Weller *et al.* (2020)
Total		-324,032	-1,416,448		
Annual average		-21,602	-94,430		
3%	Total PV			$126.9	$187.5
	Annualized			$10.3	$15.3
7%	Total PV			$111.2	$168.6
	Annualized			$11.4	$17.3

[1] Includes costs for additional monitoring of 5 percent of known leaks, each year, due to extreme events or other conditions that may change the leakage rate or cause gas to migrate.
Source: PHMSA analysis

4.2.3 Other Reporting and Recordkeeping

The proposed rule includes several requirements that may increase reporting and recordkeeping activities for gas distribution system operators. These include:

- Developing written procedures for the grading and repairing leaks, including documenting leak investigations, prioritizing repairs of certain grade 2 leaks (§192.760(a)(1))
- Documenting post-repair evaluation (§192.760(e))
- Submitting requests to PHMSA in cases where an extension of the leak remediation time interval requirements is needed for an individual leak (§192.760(h))
- Recording the history of each leak, including leak discovery, grading, monitoring, remediation, upgrades, and downgrades, and maintaining these records for a period of 5 years (records of repairs must be maintained for the life of the pipeline) (§192.760(i)(1)-(2))
- Documenting the leak detection equipment choice analysis (§192.763(f))
- Recording leak detection equipment calibration (and re-calibration) and maintaining these records for the life of the equipment (§192.763(h)(2))
- Recording repair or replacement of a pressure relief device and maintaining these records for the life of the pipeline (§192.773(c))
- Reporting intentional or unintentional large volume release of gas of 1 MMcf or more to PHMSA (§191.19)

Additionally, PHMSA is also revising Part C of the Gas Distribution System annual report form (PHMSA Form F7100.1-1) to require operators to submit additional information about the number of leaks discovered and repaired by grade.

As noted in sections 4.2.1 and 4.2.2, costs for leak surveys, repairs (including post-repair evaluations), and monitoring are assumed to include the documentation of these activities in accordance with company practices. Some of these records—for example records of repairs—are already required under various regulations; others are necessary for the proper operation of the pipeline systems and effective implementation of integrity management plans. Similarly, proper operation and maintenance of leak survey equipment is included in the survey unit costs. This includes recalibration of leak detection equipment upon malfunction indication, consistent with equipment manufacturer recommendations. To avoid double-counting, PHMSA does not provide separate costs for this analysis, but the burden hours are accounted for in the ICR required under the PRA of 1995. See section 8.6 for further discussion.

PHMSA expects that all gas distribution system operators currently have a written procedure for grading and repairing leaks as part of their Distribution Integrity Management Program (DIMP) or other programs but will need to revise their existing procedure to comply with the proposed rule requirements. Similarly, all operators will need to document the analysis supporting the selection of leak detection equipment meeting performance requirements in the proposed rule. Following the approach described in section 4.1.5, PHMSA assumed 61.5 hours and 23 hours, respectively for developing or updating these documents. Each of the 1,338 unique distribution system operators is expected to complete these revisions once at the start of the period of analysis.

PHMSA estimated that it may receive 1,000 requests per year to extend the deadline for remedying leaks on distribution lines, with each of these requests requiring approximately 8 hours to prepare (PHMSA BPJ). This number is approximately 5 percent of the total number of grade 3 leaks PHMSA estimated to be discovered each year using LDAR methods. This is likely an upper bound estimate given the additional costs involved and operators would only seek an extension if they are unable to make the repair. PHMSA notes that the cost analysis also overstates compliance costs by not accounting for the value of delaying repairs (in section 4.2.2) for the share of leaks for which operators may seek an extension.

PHMSA does not have information on the number of pressure relief devices that release gas to the atmosphere at a pressure below the set pressure, or the number of such devices that may be repaired or replaced annually under the proposed rule. For purpose of this analysis, PHMSA assumed that each operator may need to document repairs or replacement of two devices per year (*i.e.*, total of 2,676 activities per year) with the associated documentation requiring 2 hours. Like for gathering and transmission, the installation of appropriately sized pressure relief devices, verification of their correct functioning, and repair or replacement as needed, are already standard practice under the baseline and the only change under the proposed rule is the documentation of such activities.

All 1,338 distribution operators are already required to submit incident and annual reports to PHMSA and should therefore have in place the procedures, forms, and training to readily extend their current reporting, but the actual reporting could result in additional costs. New reporting requirements for intentional releases of 1 MMcf or more and unintentional releases between 1 and 3 MMcf will result in additional reports submitted to PHMSA each year. For this analysis, PHMSA assumed that gas distribution operators would submit a total of 200 reports, on average, each year, with each report estimated to require 12 hours to prepare.[60] For context, PHMSA currently receives approximately 200 gas distribution incident reports each year (PHMSA, 2021b), so this assumption is equivalent to saying that the proposed rule will double the total number of incidents reported each year.

[60] See section 4.1.5 for details.

PHMSA estimated that additional information to be reported in the Annual Distribution Report will add approximately 6 hours to the existing burden, consistent with the assumption used for gathering and transmission pipelines in section 4.1.5. This estimate is based on PHMSA's expectation that operators already track this type of information in the baseline as part of their leak management program under DIMP or other pipeline management programs but may need additional time to compile it for this report.

PHMSA estimated costs based on the assumed hour burdens and weighted-average loaded labor costs for selected occupations in the natural gas distribution industry of $88.27 per hour (Table 28). Table 29 presents PHMSA's estimates of the total annualized costs associated with reporting and recordkeeping activities not already included in the surveys, repair, and monitoring costs. The total costs are $2.4 million and $2.6 million at 3- and 7-percent discount rates, respectively, which is equivalent to $1,831 and $1,989 per operator per year (based on the 1,322 operators of gas distribution pipelines).

PHMSA welcomes data and comments on the estimated burden and associated labor costs for the additional reporting and recordkeeping activities resulting from the proposed rule, and on the baseline reporting and recordkeeping practices already implemented by gas distribution operators.

Table 28: Estimated unit labor cost for gas distribution reporting requirements

Occupation Code	Occupation Category	Hourly wage rate[1] (2019$/hour)	Total labor cost[2] (2020$/hour)	Estimated % of reporting burden
13-1040	Compliance Officers	$44.20	$65.70	40%
23-1010	Lawyers and Judicial Law Clerks	$91.63	$136.20	20%
17-2000	Engineers	$54.18	$80.53	20%
11-0000	Management Occupations	$71.25	$105.91	10%
15-1240	Database Administrators	$54.17	$80.52	10%
		Weighted average	**$88.27**	100%

[1] Reflects hourly wages for the listed occupations in NAICS 221200
[2] Adjusts the hourly wages to 2020 dollars using the employment cost index (ECI) (1.03) and scales them to total labor costs based on employer cost data for the trade, transportation, and utilities sectors indicating that wages represent 69.2% of total compensation.
Source: Bureau of Labor Statistics, 2020, 2021b, 2021c

Table 29: Incremental annualized costs of gas distribution system reporting and recordkeeping requirements

Requirement	Costing assumptions			Annualized cost (Million 2020$)[1]	
	Count	Burden (hours)	Life (years)	3%	7%
Written procedures for grading and repairing leaks	1,322	61.5	15	$0.6	$0.7
Requests for extension of leak remediation time	1,000	8.0	1	$0.7	$0.7
Leak detection equipment choice analysis	1,322	23.0	15	$0.2	$0.3
Report of incidents involving large volume releases of gas	200	12.0	1	$0.2	$0.2
Additional reporting of leaks in the Annual Distribution Report	1,322	6.0	1	$0.7	$0.7
Total[2]				**$2.4**	**$2.6**

Table 29: Incremental annualized costs of gas distribution system reporting and recordkeeping requirements
[1] Annualized reporting and recordkeeping costs are calculated by multiplying the count of activities *n* by the burden hours *h* and total labor costs *w* and then annualizing this cost over the life of the activities *t* using the discount rate *r* (3 percent or 7 percent), *i.e.*, $n \times h \times w \times \frac{r}{1-(1+r)^{-t}}$ [2] Total may not add up due to independent rounding. *Source: PHMSA analysis*

4.2.4 Gas Distribution Total Costs

Table 30 presents the total estimated costs of the proposed rule requirements for gas distribution systems, including leakage surveys, repairs, monitoring, and reporting and recordkeeping.

Table 30: Total costs of proposed rule requirements for gas distribution systems over period of analysis (million 2020$)

Year		Lamb *et al.* (2015)	Weller *et al.* (2020)
2024		$600	$658
2025		$594	$667
2026		$795	$1,151
2027		$737	$1,082
2028		$561	$874
2029		$449	$633
2030		$427	$487
2031		$425	$490
2032		$423	$492
2033		$422	$494
2034		$421	$497
2035		$420	$500
2036		$420	$503
2037		$421	$507
2038		$422	$510
3%	**Total PV**	**$6,323**	**$8,042**
	Annualized	**$514**	**$654**
7%	**Total PV**	**$5,162**	**$6,594**
	Annualized	**$530**	**$677**
Source: PHMSA analysis			

4.3 Other Gas Facilities

4.3.1 Reporting and Recordkeeping

The proposed new requirements to report large-volume releases (§191.19) apply to operators of other gas facilities (LNG facilities and UNGSFs). Following the assumptions used for gas gathering, transmission and distribution, PHMSA estimated that each report requires 12 hours to prepare.[61]

Operators of LNG facilities have reported a total of 25 incidents in the 8.5 years reflected in the incident data PHMSA reviewed for this analysis (2012 through July 2021), or approximately 3 incidents per year. Assuming that large-volume releases double the number of incidents

61 See section 4.1.5 for details.

reported each year from LNG facilities, the requirement represents an additional burden of 36 hours per year (3 reports × 12 hours).

Operators of UNGSFs have reported a total of 20 incidents during the 3.5-year period since being required to submit incident reports to PHMSA (January 2017 through July 2020), which is slightly fewer than 6 incidents per year. Making a similar assumption that large-volume releases double the number of incidents reported each year, the requirement represents an additional burden of 72 hours per year (6 reports × 120 hours).

The burden of large-volume release reports estimated to arise from the two types of other gas facilities is estimated at 36 hours per year, which is approximately $9,500 per year using the hourly labor rate for the distribution sector ($88.27/hour; see Table 28).

PHMSA welcomes data and comments on the estimated burden and associated labor costs for the additional reporting and recordkeeping activities resulting from the proposed rule, and on the baseline reporting and recordkeeping practices already implemented by operators of other gas facilities.

4.4 Total Costs for Proposed Rule

Table 31 summarizes the total costs of the proposed rule requirements for all three pipeline segments (gas gathering, gas transmission, and gas distribution) and for other gas facilities.

Table 31: Total annualized costs (million 2020$)

Segment	Basis	3% Discount rate	7% Discount rate
Gas gathering		$211	$207
Gas transmission		$15	$15
Gas distribution	Lamb *et al.* (2015)	$514	$530
	Weller *et al.* (2020)	$654	$677
Other gas facilities[1]		$0	$0
Total costs[2]	**Low**	**$740**	**$753**
	High	**$880**	**$900**

[1] Annualized costs to other gas facilities are approximately $9,900.
[2] Total reflects the range of costs for gas distribution operators based on emission factors from Lamb *et al.* (2015) (Low) and from Weller *et al.* (2020) (High). The costs for gas gathering, gas transmission and gas distribution may not add up to the total due to independent rounding.
Source: PHMSA analysis

PHMSA notes that these costs are those incurred by operators, and do not include certain costs that may be incurred by society in the form of environmental and other impacts of conducting surveys (*e.g.*, increased fuel combustion). These impacts, which for the purpose of this analysis are categorized as disbenefits, are discussed in section 5 as part of the discussion of the environmental benefits of the proposed rule.

4.5 Uncertainty and Limitations

Table 32 highlights the principal sources of uncertainties and limitations present in the cost analysis. Where feasible, the table notes the direction of any resulting bias in the cost analysis (*i.e.*, whether the assumptions PHMSA made for the analysis result in costs being over- or understated, all else being equal).

Table 32: Principal sources of uncertainty in the cost analysis.		
Item	**Sources of uncertainty**	**Direction of the impact**
Baseline practices	PHMSA made assumptions regarding leak survey, repair, and other practices operators implement in the baseline (*e.g.*, survey frequency, survey method, timing of repairs). To the extent that operators implement practices that are closer to those required under the proposed rule, incremental costs may be lower than PHMSA estimated. Conversely, if operators implement practices that are farther apart from proposed rule requirements, costs may be higher than PHMSA estimated.	Direction unknown
Attribution of leak repair costs to the proposed rule	The proposed rule is estimated to result in a greater number of leaks identified due to the requirement to employ more effective leak detection method. The analysis attributes all incremental repair costs to the proposed rule even though repairs of leaks determined to be hazardous are already required under the baseline requirements and some leaks that are discovered as a result of using more effective leak detection methods and repaired may have been discovered later as they became more significant and hazardous, and repaired then.	Overstate costs
Effectiveness of leak surveys	There is uncertainty with respect to the effectiveness of both the traditional leak detection methods and ALD methods. The results of the analysis are sensitive to the difference in effectiveness between baseline practices and ALD methods. PHMSA assumed that baseline practices detect 85 percent of the leaks that would be identified using ALD methods (*i.e.*, 85 percent "relative effectiveness"), and that the differences between the effectiveness of baseline leak surveys and leak surveys using ALD methods is uniform across leak types and sizes. Actual effectiveness is expected to vary based on the survey method and the type and size of the leak.	Direction unknown
Gas gathering and gas transmission survey costs	PHMSA applied the same survey unit cost in the baseline and proposed rule scenarios. This cost may reflect a variety of leak survey techniques, including both ground and aerial surveys. If operators have lower baseline survey costs, particularly when not required to use instrumentation, then the analysis understates the incremental cost of implementing instrumented surveys or ALD.	Understate costs
Baseline gas distribution survey costs	PHMSA estimated the baseline survey unit costs using a small sample of operators that already implement some ALD practices and therefore the baseline distribution survey costs ($1,370/mile) are assumed to be the same as unit costs under the proposed rule. If operators have lower baseline survey costs when not implementing ALD, then the analysis understates the incremental costs of implementing ALD.	Understate costs

Table 32: Principal sources of uncertainty in the cost analysis.		
Item	**Sources of uncertainty**	**Direction of the impact**
Future gas distribution survey costs	PHMSA assumed that operators would scale up their existing survey practices, provided those practices meet the performance criteria under the proposed rule. For example, in costing requirements proposed for distribution pipelines, PHMSA estimated at $1,370/mile the cost of conducting surveys using a combination of vehicle-mounted and hand-held monitors to screen, pinpoint, and grade leaks, based on baseline practices employed by selected local distribution companies. New technologies and economies of scale could reduce those unit costs in the future. For example, air-based system could provide cost-effective solutions for monitoring lines in remote areas, with recent information suggesting costs of $387 per mile (Southern California Gas Company, 2020)	Overstate costs
Use of "average" values	The analysis makes reasonable assumptions for several variables that affect the costs (and benefits) of the rule. For gathering and transmission, this includes the immediate repair of all leaks, regardless of grade. For distribution, this includes the elapsed time between grade 3 leak discovery and repairs, the share of grade 3 leaks fixed in the same year they are discovered, the share of emissions associated with leaks that meet the grade 2 definition, etc. PHMSA recognizes that practices differ across operators and from leak to leak. Actual practices and associated costs or effectiveness is expected to vary across operators.	Direction unknown
	The proposed rule is performance-based and does not mandate use of a specific technology but instead provides flexibility to operators to implement practices that fit their particular conditions. The costs of these practices will vary depending on the location, accessibility, and other attributes of the systems. For this analysis, PHMSA used unit costs based on a small sample of operator budgets or plans. Costs for individual operators are expected to vary. For example, costs for repairing individual leaks may differ from the average unit cost of $5,650/leak ($5,868/leak including post-repair inspection).	Direction unknown
Historic plastic distribution mains	PHMSA did not differentiate requirements for "historic" plastic mains in the analysis. Certain types of historic plastic mains with known leak issues are subject to more frequent leak surveys in the baseline. However, PHMSA lacks data on how much mileage of these historic mains exists. To the extent that operators currently survey these lines annually, the effects of the proposed rule will be less than estimated.	Overstate costs
Odorization of gas in part 192-regulated gathering and transmission and pipelines	PHMSA assumed that *intrastate* Class 3 and Class 4 natural gas transmission lines are odorized, and all other lines (*e.g.*, all interstate lines, intrastate lines in Class 1 and 2, gathering lines, and lines that transport commodities other than natural gas) are not odorized. The proposed rule requirements increase the frequency of surveys for a subset of odorized lines that are either leak prone or in an HCA. To the extent that more lines are odorized and are either leak prone or in an HCA, then the analysis would understate the additional number of surveys conducted and leaks.	Understate costs

Table 32: Principal sources of uncertainty in the cost analysis.		
Item	**Sources of uncertainty**	**Direction of the impact**
Baseline surveys for Type C gathering lines	PHMSA conservatively assumed that operators do not currently conduct leakage surveys on Type C gathering lines that are not subject to the existing leakage survey requirements of §192.706, consistent with information PHMSA received during the development of the Expansion of Gas Gathering Regulation (PHMSA, 2021c). To the extent that operators survey Type C lines in the baseline, the incremental costs attributable to the proposed rule would be less.	Overstate costs
Leak incidence rates	The estimated number of leaks discovered during surveys and needing to be repaired or monitored is sensitive to the assumed leak incidence rates. For distribution, PHMSA used average rates from published studies (*e.g.*, Weller *et al.*, 2020) that reflect the sensitivity of detection methods and conditions at the time each study was conducted. PHMSA presents estimates as a range to reflect the uncertainty suggested by differences across studies. To the extent that leak incidence rates tend to increase over time as pipelines age, the use of these literature values may understate the number of leaks discovered and repaired. Conversely, in cases where operators find and repair unknown leaks and replace their leak-prone pipes over time, the use of these literature values may overstate the number of leaks. For gathering and transmission, PHMSA derived leak incidence rates based on leaks reported by operators as part of the annual reports. To the extent that these leaks are only a subset of existing leaks, the analysis may understate the number of leaks.	Direction unknown
Extension of leak remediation timeline	PHMSA assumed that it would receive requests from distribution operators to extend the deadline for remedying leaks but did not account for the associated delays when modeling the number of repairs that may be completed each year. PHMSA does not have information to estimate when these leaks would be repaired. To the extent that some repairs would be delayed beyond the analyzed schedule, costs may be overstated.	Overstate costs
Unit costs of acquisition of leak detection equipment and costs of implementation (procedure development, training, and execution) advanced leak detection programs for in connection with gas pipelines transporting flammable, toxic, and corrosive gasses other than natural gas	PHMSA assumed that the costs associated with acquisition of commercially available advanced leak detection for flammable, toxic, and corrosive gasses (other than natural gas) subject to the proposed rule are the same as those for natural gas pipelines. PHMSA notes that the unit costs for such equipment may vary from one gas to the next. Similarly, PHMSA assumed that the costs associated with implementation of advanced leak detection programs for those gases would be the same as those for natural gas pipelines. PHMSA notes that the costs of conducting leak surveys may vary from one gas to the next.	Direction unknown

Table 32: Principal sources of uncertainty in the cost analysis.		
Item	**Sources of uncertainty**	**Direction of the impact**
Leak incidence rates and unit costs of repairs of gas pipelines transporting flammable, toxic, or corrosive gasses other than natural gas	PHMSA assumed that the leak incidence rates and costs associated with repairs on gas pipelines transporting flammable, toxic, and corrosive gasses (other than natural gas) as a result of the proposed rule would be the same as those for natural gas pipelines.	Direction unknown

5 Benefits Analysis

The proposed rule aims to reduce the amount of gas lost to the atmosphere as operators improve their leak detection programs and accelerate repairs. Expected benefits will include avoided loss of gas, climate benefits from avoided methane emissions and other environmental impacts, reduced risk of accidents, human health benefits from reducing emissions of VOCs and HAPs contained in unprocessed natural gas, and other effects such as reduced odors and nuisance.

The sections below describe, and where possible quantify and monetize, the expected benefits of the proposed rule.

5.1 Environmental Benefits

The principal environmental benefits of the proposed rule relate to the reduction of methane emissions and the associated mitigation of the climate change threat.

Methane is more than 25 times as potent as carbon dioxide at trapping heat in the atmosphere. Anthropogenic emissions of methane are responsible for about one third of the warming due to well-mixed greenhouse gases (Intergovernmental Panel on Climate Change, 2021). Methane is also an important precursor to the formation of tropospheric (*i.e.*, ground-level) ozone. Ground-level ozone, itself a greenhouse gas, is a regulated air pollutant responsible for harmful effects on human health and damages to crops and vegetation. The sections below describe the approach PHMSA used to estimate the climate-related benefits from reducing methane emissions through more timely discovery and repair of leaks of natural gas, landfill gas, and synthetic gas from gathering, transmission, and distribution systems. Natural gas is composed of 79 to 93 percent methane, depending on the production region and processing stage; EPA estimates that natural gas is 87.0 percent methane following processing (in gathering pipelines), whereas natural gas transmitted and distributed is 93.4 percent methane (EPA, 2021a; EPA, 2022a). Methane also represents roughly 50 percent of landfill gas (before further processing; EPA, undated) and, depending on the gasification source, 0 to 5 percent of synthetic gas (U.S. Department of Energy National Energy Technology Laboratory, n.d.).

There may also be additional benefits from reducing indirect effects of atmospheric methane as precursor to global background concentrations of tropospheric ozone. These effects are difficult to quantify and monetize but PHMSA expects the benefits to be small when compared to those associated with climate impacts.

Pipeline surveys and other activities resulting from the proposed rule requirements may have environmental impacts. PHMSA did not quantify the associated disbenefits but expect them to be comparably small. For example, increased reliance on mobile survey methods using vehicle- or aerial-based platforms could increase the number of miles driven with vehicles and the associated transportation emissions. Overall, PHMSA expects incremental emissions and other environmental impacts of leakage surveys to be small when compared to the methane emissions detected and avoided as a result of the surveys. For example, EPA estimates that the average passenger vehicle emits about 404 grams of carbon dioxide (CO_2) per mile driven (EPA, 2018). A vehicle driving along distribution mains three times, as is the practice for some mobile surveys, would emit less than 0.01 to 0.7 percent of the average greenhouse gas emissions detected on the distribution main being surveyed, depending on the pipe material and assumed leak rate.[62]

The DEA document provides more details on the anticipated environmental effects of the proposed rule (PHMSA, 2023).

5.1.1 Methane Emissions Reductions

PHMSA estimated the changes in methane emissions associated with accelerating the repairs of leaks through the timelier discovery of the leaks and shorter deadlines for fixing leaks. Following the methodology described in section 2.1.5 and in Appendix A, the general approach entailed estimating, for each scenario (*e.g.*, baseline and proposed rule, and basis for distribution leak incidence rate), the cumulative number of leaks repaired as of each year and multiplying this count by the emission factor corresponding to each leak type (*e.g.*, pipeline type, leak grade, commodity) to obtain the methane emission reductions in each year. The differences between the proposed rule and the baseline represent the incremental methane reductions attributable to the proposed rule. The benefits depend, in part, on the survey, repair, and other practices operators are assumed to implement in the baseline, including the use of ALD survey techniques. Table 33 summarizes the range of avoided methane emissions over the 15-year analysis period.

For transmission and gathering pipelines, PHMSA estimated the reductions in methane emissions associated with accelerating the repairs of leaks through the timelier discovery of the leaks, and the improved effectiveness of leak detection practices under the proposed rule compared to the baseline. The same is true of estimates for distribution pipelines, but these emission reductions additionally reflect the range of incidence rates and emission factors from Table 8. As discussed in section 3.2.3, Weller *et al.* (2020) found much greater incidence of leaks in plastic and coated steel mains (nearly 9 times and 6 times greater, respectively), and much smaller incidence in bare steel and cast iron mains (approximately one fifth and one third, respectively) than Lamb *et al.* (2015). Weller *et al.* (2020) also reported emissions rates that were consistently higher across all material types than those in Lamb *et al.* (2015)—by as much as six times higher for plastic mains. These differences account for the differences between avoided methane emissions for the gas distribution segment.

To place these changes in context, PHMA estimates that methane emission reductions 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. See details of the modeling approach in section 2.1.5 and Appendix A. When compared to the GHGI emissions summarized in section 3.3, the low-bound estimate of emission reductions in the first three years represent approximately 50 percent of inventoried annual emissions from gathering, transmission and

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62 Each pipeline mile surveyed may result in 1.212 kg CO_2 in vehicle tailpipe emissions, based on three passes. This is compared to annual emission factors for distribution mains ranging between approximately 182 and 21,300 kg CO_{2e} per mile, depending on the pipe material (1 kg CH_4 is equivalent to 21 kg CO_2). See section 3.3 for details on distribution main emission factors.

distribution leaks in 2020 (see Table 7; EPA, 2022a; EPA, 2022e). The high-bound estimate of emission reductions represents a significantly greater share (about 100 percent) of the inventoried emissions in 2020, but this is to be expected since it is based on different assumptions regarding baseline distribution emissions. As discussed in section 3.3, the incidence rates and emission factors from Weller *et al*. (2020) are greater than the values EPA used in developing the inventory.

Table 33: Changes in methane emissions (metric ton CH_4)

Year	Gathering	Transmission	Distribution		Total[1]	
			Lamb *et al.* (2015)	Weller *et al.* (2020)	Low[2]	High[2]
2024	-52,300	-1,300	-42,280	-115,300	-95,900	-168,900
2025	-79,000	-1,900	-82,470	-229,900	-163,300	-310,800
2026	-106,000	-2,500	-135,400	-423,500	-243,800	-532,000
2027	-133,400	-3,100	-179,300	-588,400	-315,800	-724,900
2028	-161,300	-3,700	-206,400	-699,400	-371,300	-864,300
2029	-189,500	-4,300	-223,100	-770,700	-416,900	-964,500
2030	-218,100	-4,900	-237,500	-817,200	-460,500	-1,040,200
2031	-247,100	-5,600	-251,600	-863,800	-504,200	-1,116,400
2032	-276,500	-6,200	-265,300	-910,600	-547,900	-1,193,300
2033	-306,300	-6,800	-278,600	-957,600	-591,700	-1,270,800
2034	-336,500	-7,500	-291,500	-1,005,000	-635,500	-1,348,900
2035	-367,200	-8,100	-304,200	-1,052,000	-679,500	-1,427,700
2036	-398,300	-8,800	-316,700	-1,100,000	-723,800	-1,507,300
2037	-429,800	-9,500	-329,000	-1,148,000	-768,300	-1,587,600
2038	-461,800	-10,100	-341,200	-1,197,000	-813,100	-1,668,700

Negative values represent reduced methane emissions under the proposed rule, *i.e.*, net benefits.
[1] Total may not add up due to independent rounding.
[2] The low estimate reflects distribution emissions based on Lamb *et al.* (2015) whereas the high estimate reflects distribution emissions based on Weller *et al.* (2020).
Source: PHMSA analysis

As noted in section 3.5, measures mandated by Section 114 of the PIPES Act of 2020 to reduce intentional venting of natural gas during scheduled repairs are expected to be implemented in the baseline and therefore PHMSA did not attribute the reductions to the proposed rule even though these measures are expected to also have environmental benefits. See section 6.1 for the analysis of costs and benefits relative to the pre-statutory baseline.

5.1.2 Social Cost of Methane

PHMSA estimated the climate benefits of this proposed rule using estimates of the social cost of greenhouse gases (SC-GHG), specifically the social cost of methane (SC-CH_4). The SC-CH_4 is the monetary value of the net harm to society associated with a marginal change in methane emissions in a given year, or the benefit of avoiding these emissions. In principle, SC-GHG includes the value of all climate change impacts (both negative and positive), including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-GHG, therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect GHG emissions. In practice, data and modeling limitations naturally restrain the ability of SC-

GHG estimates to include all the important physical, ecological, and economic impacts of climate change, such that the estimates are a partial accounting of climate change impacts and will therefore, tend to be underestimates of the marginal benefits of abatement.[63]

In 2017, the National Academies of Sciences, Engineering, and Medicine published a report that provides a roadmap for how to update SC-GHG estimates used in Federal analyses going forward to ensure that they reflect advances in the scientific literature (National Academies of Sciences, 2017b). The National Academies' report recommended specific criteria for future SC-GHG updates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process. The research community has made considerable progress in developing new data and methods that help to advance various components of the SC-GHG estimation process in response to the National Academies' recommendations.

In Executive Order (E.O.) 13990, Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, President Biden called for a renewed focus on updating estimates of the social cost of greenhouse gases (SC-GHG) to reflect the latest science, noting that "it is essential that agencies capture the full benefits of reducing greenhouse gas emissions as accurately as possible." Important steps have been taken to begin to fulfill this directive of E.O. 13990. In February 2021, the Interagency Working Group on the SC-GHG (IWG) released a technical support document (hereinafter the "February 2021 TSD") that provided a set of IWG recommended SC-GHG estimates while work on a more comprehensive update is underway to reflect recent scientific advances relevant to SC-GHG estimation (IWG, 2021). In addition, as discussed further below, EPA has developed a draft updated SC-GHG methodology within a sensitivity analysis in the regulatory impact analysis of EPA's November 2022 supplemental proposal for oil and gas standards that is currently undergoing external peer review and a public comment process.[64]

The SC-CH_4 estimates used in this analysis (Table 34) are based on the IWG's recommended interim estimates. PHMSA has evaluated the SC-GHG estimates in the February 2021 TSD and has determined that these estimates are appropriate for use in estimating the climate benefits from CH_4 emissions reductions expected to occur as a result of the proposed rule and alternative standards. These SC-GHG estimates are interim values developed for use in benefit-cost analyses until updated estimates of the impacts of climate change can be developed based on the best available science and economics. After considering the TSD, and the issues and studies discussed therein, PHMSA concludes that these estimates, while likely an underestimate, are the best currently available SC-GHG estimates until revised estimates have been developed reflecting the latest, peer-reviewed science.

The SC-GHG estimates presented in the February 2021 SC-GHG TSD and used in this PRIA were developed over many years, using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. Specifically, in

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63 Federal agencies began regularly incorporating SC-CO_2 estimates in their benefit-cost analyses conducted under Executive Order (E.O.) 12866 since 2008, following a Ninth Circuit Court of Appeals remand of a rule for failing to monetize the benefits of reducing CO_2 emissions in that rulemaking process.

64 See https://www.epa.gov/environmental-economics/scghg.

2009, an IWG that included DOT and other executive branch agencies and offices was established to develop estimates relying on the best available science for agencies to use. The IWG published SC-CO_2 estimates in 2010 that were developed from an ensemble of three widely cited integrated assessment models (IAMs) that estimate global climate damages using highly aggregated representations of climate processes and the global economy combined into a single modeling framework. The three IAMs were run using a common set of input assumptions in each model for future population, economic, and CO_2 emissions growth, as well as equilibrium climate sensitivity (ECS) – a measure of the globally averaged temperature response to increased atmospheric CO_2 concentrations. These estimates were updated in 2013 based on new versions of each IAM.[65] In August 2016 the IWG published estimates of the social cost of methane (SC-CH_4) and nitrous oxide (SC-N_2O) using methodologies that are consistent with the methodology underlying the SC-CO_2 estimates. The modeling approach that extends the IWG SC-CO_2 methodology to non-CO_2 GHGs has undergone multiple stages of peer review.[66] In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the SC-CO_2 estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the SC-CO_2 estimates to offer advice on how to approach future updates to ensure that the estimates continue to reflect the best available science and methodologies. In January 2017, the National Academies released their final report, *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide* and recommended specific criteria for future updates to the SC-CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process (National Academies of Sciences, 2017a, 2017b). Shortly thereafter, in March 2017, President Trump issued Executive Order 13783, which disbanded the IWG, withdrew the previous TSDs, and directed agencies to ensure SC-GHG estimates used in regulatory analyses are consistent with the guidance contained in OMB's Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5). Benefit-cost analyses following E.O. 13783 used SC-GHG estimates that attempted to focus on the specific share of climate change damages in the U.S. as captured by the models (which did not reflect many pathways by which climate impacts affect the welfare of U.S. citizens and residents) and were calculated using two default discount rates recommended by Circular A-4, 3 percent and 7 percent.[67] All other methodological

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65 Dynamic Integrated Climate and Economy (DICE) 2010 (Nordhaus, 2010), Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) 3.8 (Anthoff & Tol, 2013a, 2013b), and Policy Analysis of the Greenhouse Gas Effect (PAGE) 2009 (Hope, 2013).

66 See IWG, 2016 for more discussion of the SC-CH4 and SC-N2O and the peer review and public comment processes accompanying their development.

67 Some regulatory analyses under E.O. 13783 included sensitivity analyses based on global SC-GHG values and using a lower discount rate of 2.5%. OMB Circular A-4 (OMB, 2003) recognizes that special considerations arise when applying discount rates if intergenerational effects are important. In the IWG's 2015 Response to Comments, OMB—as a co-chair of the IWG—made clear that "Circular A-4 is a living document," that "the use of 7 percent is not considered appropriate for intergenerational discounting," and that "[t]here is wide support for this view in the academic literature, and it is recognized in Circular A-4 itself." OMB, as part of the IWG, similarly repeatedly confirmed that "a focus on global SCC estimates in [regulatory impact analyses] is appropriate" (IWG, 2015).

decisions and model versions used in SC-GHG calculations remained the same as those used by the IWG in 2010 and 2013, respectively.

On January 20, 2021, President Biden issued E.O. 13990, which re-established an IWG and directed it to develop an update of the SC-GHG estimates that reflect the best available science and the recommendations of the National Academies. In February 2021, the IWG recommended the interim use of the most recent SC-GHG estimates developed by the IWG prior to the group being disbanded in 2017, adjusted for inflation (IWG, 2021). As discussed in the February 2021 TSD, the IWG's selection of these interim estimates reflected the immediate need to have SC-GHG estimates available for agencies to use in regulatory benefit-cost analyses and other applications that were developed using a transparent process, peer reviewed methodologies, and the science available at the time of that process.

As noted above, DOT participated in the IWG but has also independently evaluated the interim SC-GHG estimates published in the February 2021 TSD and determined they are appropriate to use to estimate climate benefits for this action. DOT and other agencies intend to undertake a fuller update of the SC-GHG estimates that takes into consideration the advice of the National Academies of Sciences, 2017a; National Academies of Sciences (2017b) and other recent scientific literature. PHMSA has also evaluated the supporting rationale of the February 2021 TSD, including the studies and methodological issues discussed therein, and concludes that it agrees with the rationale for these estimates presented in the TSD and summarized below.

In particular, the IWG found that the SC-GHG estimates used under E.O. 13783 fail to reflect the full impact of GHG emissions in multiple ways. First, the IWG concluded that those estimates fail to capture many climate impacts that can affect the welfare of U.S. citizens and residents. Examples of affected interests include direct effects on U.S. citizens and assets located abroad, international trade, and tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. Those impacts are better captured within global measures of the social cost of greenhouse gases.

In addition, assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. A wide range of scientific and economic experts have emphasized the issue of reciprocity as support for considering global damages of GHG emissions. Using a global estimate of damages in U.S. analyses of regulatory actions allows the U.S. to continue to actively encourage other nations, including emerging major economies, to take significant steps to reduce emissions. The only way to achieve an efficient allocation of resources for emissions reduction on a global basis—and so benefit the U.S. and its citizens—is for all countries to base their policies on global estimates of damages.

As a member of the IWG involved in the development of the February 2021 SC-GHG TSD, DOT agrees with this assessment and, therefore, in this PRIA, PHMSA centers attention on a global measure of SC-CO_2. This approach is the same as that taken in DOT regulatory analyses over 2009 through 2016. A robust estimate of climate damages only to U.S. citizens and residents that accounts for the myriad of ways that global climate change reduces the net welfare of U.S. populations does not currently exist in the literature. As explained in the February 2021 TSD, existing estimates are both incomplete and an underestimate of total damages that accrue to the citizens and residents of the U.S. because they do not fully capture the regional interactions and spillovers discussed above, nor do they include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature, as discussed further below. DOT, as a member of the IWG, will continue to review developments in the literature, including more robust methodologies for estimating the magnitude of the various damages to U.S. populations from climate impacts and reciprocal international mitigation activities, and explore ways to better inform the public of the full range of carbon impacts.

Second, the IWG concluded that the use of the social rate of return on capital (7 percent under current OMB Circular A-4 guidance) to discount the future benefits of reducing GHG emissions inappropriately underestimates the impacts of climate change for the purposes of estimating the SC-GHG. Consistent with the findings of the National Academies of Sciences (2017b) and the economic literature, the IWG continued to conclude that the consumption rate of interest is the theoretically appropriate discount rate in an intergenerational context (IWG, 2013; IWG, 2010; IWG, 2016), and recommended that discount rate uncertainty and relevant aspects of intergenerational ethical considerations be accounted for in selecting future discount rates.[68] Furthermore, the damage estimates developed for use in the SC-GHG are estimated in consumption-equivalent terms, and so an application of OMB Circular A-4's guidance for regulatory analysis would then use the consumption discount rate to calculate the SC-GHG. PHMSA agrees with this assessment and will continue to follow developments in the literature pertaining to this issue. PHMSA also notes that while OMB Circular A-4, as published in 2003, recommends using 3 percent and 7 percent discount rates as "default" values, Circular A-4 also reminds agencies that "different regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues and the sensitivity of the benefit and cost estimates to the key assumptions." On discounting, Circular A-4 recognizes that "special ethical considerations arise when comparing benefits and costs across generations," and Circular A-4 acknowledges that analyses may appropriately "discount future costs and consumption benefits…at a lower rate than for intragenerational analysis." In the 2015 Response to Comments on the Social Cost of Carbon for Regulatory Impact Analysis, OMB, DOT, and the other IWG members recognized that "Circular A-4 is a living document" and "the use of 7 percent is not considered appropriate for intergenerational discounting. There is wide support for this view in the academic literature, and it is recognized in Circular A-4 itself." Thus, PHMSA concludes that a 7 percent discount rate is not appropriate to apply to value the social cost of greenhouse gases in the analysis presented in this RIA. In this analysis, to calculate the present and annualized values of climate benefits, PHMSA uses the same discount rate as the rate used

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68 GHG emissions are stock pollutants, where damages are associated with what has accumulated in the atmosphere over time, and they are long lived such that subsequent damages resulting from emissions today occur over many decades or centuries depending on the specific greenhouse gas under consideration. In calculating the SC-GHG, the stream of future damages to agriculture, human health, and other market and non-market sectors from an additional unit of emissions are estimated in terms of reduced consumption (or consumption equivalents). Then that stream of future damages is discounted to its present value in the year when the additional unit of emissions was released. Given the long time horizon over which the damages are expected to occur, the discount rate has a large influence on the present value of future damages.

to discount the value of damages from future GHG emissions, for internal consistency. That approach to discounting follows the same approach that the February 2021 TSD recommends "to ensure internal consistency—*i.e.*, future damages from climate change using the SC-GHG at 2.5 percent should be discounted to the base year of the analysis using the same 2.5 percent rate." PHMSA has also consulted the National Academies' 2017 recommendations on how SC-GHG estimates can "be combined in RIAs with other cost and benefits estimates that may use different discount rates." The National Academies reviewed "several options," including "presenting all discount rate combinations of other costs and benefits with [SC-GHG] estimates."

While the IWG works to assess how best to incorporate the latest, peer reviewed science to develop an updated set of SC-GHG estimates, it recommended the interim estimates to be the most recent estimates developed by the IWG prior to the group being disbanded in 2017. The estimates rely on the same models and harmonized inputs and are calculated using a range of discount rates. As explained in the February 2021 TSD, the IWG has concluded that it is appropriate for agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates as were used in regulatory analyses between 2010 and 2016 and subject to public comment. For each discount rate, the IWG combined the distributions across models and socioeconomic emissions scenarios (applying equal weight to each) and then selected a set of four values for use in agency analyses: an average value resulting from the model runs for each of three discount rates (2.5 percent, 3 percent, and 5 percent), plus a fourth value, selected as the 95th percentile of estimates based on a 3 percent discount rate. The fourth value was included to provide information on potentially higher-than-expected economic impacts from climate change, conditional on the 3 percent estimate of the discount rate. As explained in the February 2021 TSD, this update reflects the immediate need to have an operational SC-GHG that was developed using a transparent process, peer-reviewed methodologies, and the science available at the time of that process. Those estimates were subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013.

Table 34 summarizes the interim SC-CH_4 estimates for the years 2020 to 2050. These estimates are reported in 2020 dollars but are otherwise identical to those presented in the IWG's 2016 TSD (IWG, 2016). For purposes of capturing uncertainty around the SC-CH_4 estimates in analyses, the 2021 TSD emphasizes the importance of considering all four of the SC-CH_4 values. The SC-CH_4 increases over time within the models – *i.e.*, the societal harm from one metric ton emitted in 2030 is higher than the harm caused by one metric ton emitted in 2025 – because future emissions produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to GDP.

Table 34: Interim SC-CH_4 Values, 2020 – 2050 (2020$/metric ton CH_4)				
Emissions year	**Discount rate and statistic**			
	5% Average	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2020	$670	$1,500	$2,000	$3,900
2021	$690	$1,500	$2,000	$4,000
2022	$720	$1,600	$2,100	$4,200
2023	$750	$1,700	$2,100	$4,300
2024	$770	$1,700	$2,200	$4,400
2025	$800	$1,800	$2,200	$4,500
2026	$830	$1,800	$2,300	$4,700
2027	$860	$1,900	$2,300	$4,800
2028	$880	$1,900	$2,400	$4,900
2029	$910	$2,000	$2,500	$5,100
2030	$940	$2,000	$2,500	$5,200
2031	$970	$2,100	$2,600	$5,300
2032	$1,000	$2,100	$2,600	$5,500
2033	$1,000	$2,200	$2,700	$5,700
2034	$1,100	$2,200	$2,800	$5,800
2035	$1,100	$2,300	$2,800	$6,000
2036	$1,100	$2,300	$2,900	$6,100
2037	$1,200	$2,400	$3,000	$6,300
2038	$1,200	$2,400	$3,000	$6,400
2039	$1,200	$2,500	$3,100	$6,600
2040	$1,300	$2,500	$3,100	$6,700
2041	$1,300	$2,600	$3,200	$6,900
2042	$1,400	$2,600	$3,300	$7,000
2043	$1,400	$2,700	$3,300	$7,200
2044	$1,400	$2,700	$3,400	$7,300
2045	$1,500	$2,800	$3,500	$7,500
2046	$1,500	$2,800	$3,500	$7,600
2047	$1,500	$2,900	$3,600	$7,700
2048	$1,600	$3,000	$3,700	$7,900
2049	$1,600	$3,000	$3,700	$8,000
2050	$1,700	$3,100	$3,800	$8,200

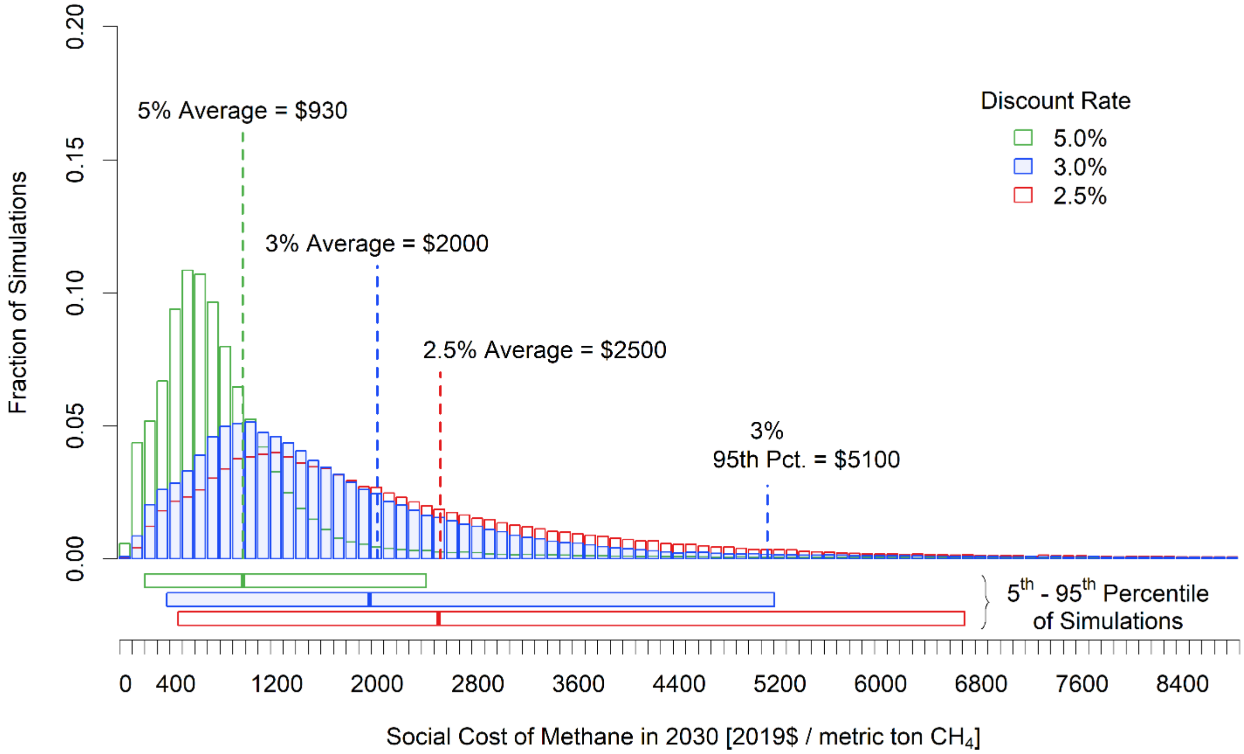
Note: These SC-CO_2 values are identical to those reported in the 2016 TSD (IWG 2016a) adjusted for inflation to 2016 dollars using the annual GDP Implicit Price Deflator values in the U.S. Bureau of Economic Analysis' (BEA) NIPA Table 1.1.9 (U.S. Bureau of Economic Analysis, 2021). The values are stated in $/metric tonne CH_4 and vary depending on the year of CH_4 emissions. This table displays rounded values; the annual unrounded values used in the calculations in this RIA are available on OMB's website: https://www.whitehouse.gov/omb/information-regulatory-affairs/regulatory-matters/#scghgs.
Source: IWG, 2021

Figure 6 presents the quantified sources of uncertainty in the form of frequency distributions for the SC-CH_4 estimates for emissions in 2030.[69] The distribution of SC-CH_4 estimates reflect uncertainty in key model parameters such as the equilibrium climate sensitivity, as well as uncertainty in other parameters set by the original model developers. To highlight the difference

69 Although the distributions and numbers in Figure 6 are based on the full set of model results (150,000 estimates for each discount rate), for display purposes the horizontal axis is truncated with 0.029 percent of the estimates falling below the lowest bin displayed and 3 percent of the estimates falling above the highest bin displayed.

between the impact of the discount rate and other quantified sources of uncertainty, the bars below the frequency distributions provide a symmetric representation of quantified variability in the SC-CH_4 estimates for each discount rate. As illustrated by the figure, the assumed discount rate plays a critical role in the ultimate estimate of the SC-CH_4. This is because GHG emissions today continue to impact society far out into the future, so with a higher discount rate, costs that accrue to future generations are weighted less, resulting in a lower estimate. As discussed in the February 2021 SC-GHG TSD, there are other sources of uncertainty that have not yet been quantified and are thus not reflected in these estimates.

Figure 6: Frequency distribution of SC-CH_4 estimates for 2030 (in 2019 dollars).



The interim SC-CH_4 estimates presented in Table 34 have a number of limitations. First, the current scientific and economic understanding of discounting approaches suggests discount rates appropriate for intergenerational analysis in the context of climate change are likely to be less than 3 percent, near 2 percent or lower (IWG, 2021). Second, the IAMs used to produce these interim estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature and the science underlying their "damage functions" — *i.e.*, the core parts of the IAMs that map global mean temperature changes and other physical impacts of climate change into economic (both market and nonmarket) damages — lags behind the most recent research. For example, limitations include the incomplete treatment of catastrophic and non-catastrophic impacts in the integrated assessment models, their incomplete treatment of adaptation and technological change, the incomplete way in which inter-regional and intersectoral linkages are modeled, uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the discount rate and uncertainty in economic growth over long time horizons.

Likewise, the socioeconomic and emissions scenarios used as inputs to the models do not reflect new information from the last decade of scenario generation or the full range of projections.

There are several limitations specific to the estimation of SC-CH_4. For example, the SC-CH_4 estimates do not reflect updates from the IPCC regarding atmospheric and radiative efficacy. Another limitation is that the SC-CH_4 estimates do not account for the direct health and welfare impacts associated with tropospheric ozone produced by methane (see *e.g.*, Sarofim *et al.*, 2017, reporting that studies have found the global ozone-related mortality benefits of CH_4 emissions reductions, which are not included in the social cost of methane valuations, to be $800 to $1,800 per metric ton of methane emissions). In addition, the SC-CH_4 estimates do not reflect that methane emissions lead to a reduction in atmospheric oxidants, like hydroxyl radicals, nor do they account for impacts associated with CO_2 produced from methane oxidizing in the atmosphere.

The individual limitations and uncertainties do not all work in the same direction in terms of their influence on the SC-CH_4 estimates. However, the IWG has recommended that, taken together, the limitations suggest that the interim SC-GHG estimates used in this RIA likely underestimate the damages from GHG emissions. In particular, the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (IPCC, 2007), which was the most current IPCC assessment available at the time when the IWG decision over the ECS input was made, concluded that SC-CO2 estimates "very likely…underestimate the damage costs" due to omitted impacts. Since then, the peer-reviewed literature has continued to support this conclusion, as noted in the IPCC's Fifth Assessment report (IPCC, 2014b) and other recent scientific assessments (*e.g.*, IPCC, 2018, 2019a, 2019b); U.S. Global Change Research Program (USGCRP, 2016, 2018a); and the National Academies of Sciences, Engineering, and Medicine (National Academies of Sciences, 2017b, 2019). These assessments confirm and strengthen the science, updating projections of future climate change and documenting and attributing ongoing changes. For example, sea level rise projections from the IPCC's Fourth Assessment report ranged from 18 to 59 centimeters by the 2090s relative to 1980-1999, while excluding any dynamic changes in ice sheets due to the limited understanding of those processes at the time (IPCC, 2007). A decade later, the Fourth National Climate Assessment projected a substantially larger sea level rise of 30 to 130 centimeters by the end of the century relative to 2000, while not ruling out even more extreme outcomes (USGCRP, 2018b). PHMSA has reviewed and considered the limitations of the models used to estimate the interim SC-GHG estimates, and concurs with the February 2021 SC-GHG TSD's assessment that, taken together, the limitations suggest that the interim SC-GHG estimates likely underestimate the damages from GHG emissions.

The February 2021 SC-GHG TSD briefly previews some of the recent advances in the scientific and economic literature that the IWG is actively following and that could provide guidance on, or methodologies for, addressing some of the limitations with the interim SC-GHG estimates. The IWG is currently working on a comprehensive update of the SC-GHG estimates taking into consideration recommendations from the National Academies of Sciences, Engineering and Medicine, recent scientific literature, public comments received on the February 2021 TSD and other input from experts and diverse stakeholder groups (National Academies of Sciences, 2017b). While that process continues, DOT is continuously reviewing developments in the scientific literature on the SC-GHG, including more robust methodologies for estimating damages from emissions, and looking for opportunities to further improve SC-GHG estimation going forward. Most recently, the EPA presented a draft set of updated SC-GHG estimates within a sensitivity analysis in the regulatory impact analysis of the EPA's November 2022 supplemental proposal for oil and gas standards that that aims to incorporate recent advances in the climate science and economics literature. Specifically, the draft updated methodology incorporates new literature and research consistent with the National Academies near-term recommendations on socioeconomic and emissions inputs, climate modeling components, discounting approaches, and treatment of uncertainty, and an enhanced representation of how physical impacts of climate change translate to economic damages in the modeling framework based on the best and readily adaptable damage functions available in the peer reviewed literature. The EPA solicited public comment on the sensitivity analysis and the accompanying draft technical report, which explains the methodology underlying the new set of estimates, in the docket for the proposed Oil and Gas rule. The EPA is also conducting an external peer review of this technical report. More information about this process and public comment opportunities is available on the EPA's website.[70] EPA's draft technical report will be among the many technical inputs available to the IWG as it continues its work, and PHMSA will likewise continue to follow its development.

5.1.3 Climate Benefits from Methane Emission Reductions

Table 35 through Table 38 show the climate change benefits estimated using all four sets of SC-CH_4 values from Table 34: the average SC-CH_4 value discounted at 5 percent, the average discounted at 3 percent, the average discounted at 2.5 percent and the 95[th] percentile discounted at 3 percent. The calculations entailed multiplying the emission reductions in Table 33 by the applicable SC-CH_4 value from Table 34 for the given year and discount rate.

Table 35: Climate benefits of avoided methane emissions based on the average SC-CH_4 value at 5 percent discount (million 2020$, discounted and annualized at 5%)

Year	Gathering	Transmission	Distribution		Total	
			Lamb *et al.* (2015)	Weller *et al.* (2020)	Low[1]	High[1]
2024	$40	$1	$33	$89	$74	$130
2025	$63	$1	$66	$184	$131	$249
2026	$88	$2	$112	$351	$202	$441
2027	$115	$3	$154	$506	$272	$623
2028	$142	$3	$182	$615	$327	$761
2029	$172	$4	$203	$701	$379	$878
2030	$205	$5	$223	$768	$433	$978
2031	$240	$5	$244	$838	$489	$1,083
2032	$276	$6	$265	$911	$548	$1,193
2033	$306	$7	$279	$958	$592	$1,271
2034	$370	$8	$321	$1,105	$699	$1,484
2035	$404	$9	$335	$1,158	$747	$1,570
2036	$438	$9	$348	$1,210	$796	$1,658
2037	$516	$11	$395	$1,378	$922	$1,905
2038	$554	$12	$409	$1,436	$975	$2,002
Total PV	**$2,500**	**$55**	**$2,341**	**$7,964**	**$4,895**	**$10,518**
Annualized	**$229**	**$5**	**$215**	**$731**	**$449**	**$965**

[70] See https://www.epa.gov/environmental-economics/scghg

Table 35: Climate benefits of avoided methane emissions based on the average SC-CH_4 value at 5 percent discount (million 2020$, discounted and annualized at 5%)						
Year	**Gathering**	**Transmission**	**Distribution**		**Total**	
			Lamb *et al.* (2015)	**Weller *et al.* (2020)**	**Low[1]**	**High[1]**

[1] 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).
Source: PHMSA analysis

Table 36: Climate benefits of avoided methane emissions based on the average SC-CH_4 value at 3 percent discount (million 2020$, discounted and annualized at 3%)						
Year	**Gathering**	**Transmission**	**Distribution**		**Total**	
			Lamb *et al.* (2015)	**Weller *et al.* (2020)**	**Low[1]**	**High[1]**
2024	$89	$2.1	$72	$196	$163	$287
2025	$142	$3.3	$148	$414	$294	$559
2026	$191	$4.4	$244	$762	$439	$957
2027	$254	$5.7	$341	$1,118	$600	$1,377
2028	$306	$6.9	$392	$1,329	$705	$1,642
2029	$379	$8.5	$446	$1,541	$834	$1,929
2030	$436	$9.7	$475	$1,634	$921	$2,080
2031	$519	$11.5	$528	$1,814	$1,059	$2,344
2032	$581	$12.8	$557	$1,912	$1,150	$2,506
2033	$674	$14.8	$613	$2,107	$1,301	$2,795
2034	$740	$16.1	$641	$2,211	$1,398	$2,967
2035	$845	$18.3	$700	$2,420	$1,563	$3,283
2036	$916	$19.8	$728	$2,530	$1,664	$3,466
2037	$1,032	$22.2	$790	$2,756	$1,843	$3,810
2038	$1,108	$23.8	$819	$2,872	$1,951	$4,004
Total PV	**$6,238**	**$136.9**	**$5,800**	**$19,762**	**$12,175**	**$26,137**
Annualized	**$507**	**$11.1**	**$472**	**$1,607**	**$990**	**$2,126**

[1] The low estimate reflects distribution emissions based on Lamb *et al.* (2015) whereas the high estimate reflects distribution emissions based on Weller *et al.* (2020).
Source: PHMSA analysis

Table 37: Climate benefits of avoided methane emissions based on the average SC-CH_4 value at 2.5 percent discount (million 2020$, discounted and annualized at 2.5%)						
Year	**Gathering**	**Transmission**	**Distribution**		**Total**	
			Lamb *et al.* (2015)	**Weller *et al.* (2020)**	**Low[1]**	**High[1]**
2024	$115	$3	$93	$254	$211	$372
2025	$174	$4	$181	$506	$359	$684
2026	$244	$6	$311	$974	$561	$1,223
2027	$307	$7	$412	$1,353	$726	$1,667
2028	$387	$9	$495	$1,679	$891	$2,074
2029	$474	$11	$558	$1,927	$1,042	$2,411
2030	$545	$12	$594	$2,043	$1,151	$2,600
2031	$642	$14	$654	$2,246	$1,311	$2,902
2032	$719	$16	$690	$2,368	$1,424	$3,102
2033	$827	$18	$752	$2,586	$1,597	$3,431
2034	$942	$21	$816	$2,814	$1,779	$3,776
2035	$1,028	$22	$852	$2,947	$1,902	$3,997
2036	$1,155	$25	$918	$3,191	$2,098	$4,371
2037	$1,289	$28	$987	$3,445	$2,304	$4,762
2038	$1,385	$30	$1,024	$3,590	$2,439	$5,005
Total PV	**$8,128**	**$178**	**$7,532**	**$25,676**	**$15,838**	**$33,982**

Table 37: Climate benefits of avoided methane emissions based on the average $SC-CH_4$ value at 2.5 percent discount (million 2020$, discounted and annualized at 2.5%)						
Year	**Gathering**	**Transmission**	**Distribution**		**Total**	
			Lamb *et al.* (2015)	**Weller *et al.* (2020)**	**Low[1]**	**High[1]**
Annualized	**$640**	**$14**	**$593**	**$2,023**	**$1,248**	**$2,678**

[1] 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).
Source: PHMSA analysis

Table 38: Climate benefits of avoided methane emissions based on the 95th percentile $SC-CH_4$ value at 3 percent discount (million 2020$, discounted and annualized at 3%)						
Year	**Gathering**	**Transmission**	**Distribution**		**Total**	
			Lamb *et al.* (2015)	**Weller *et al.* (2020)**	**Low[1]**	**High[1]**
2024	$230	$5	$186	$507	$422	$743
2025	$355	$8	$371	$1,035	$735	$1,398
2026	$498	$11	$636	$1,990	$1,146	$2,500
2027	$641	$14	$860	$2,824	$1,516	$3,479
2028	$790	$18	$1,011	$3,427	$1,819	$4,235
2029	$966	$22	$1,138	$3,931	$2,126	$4,919
2030	$1,134	$25	$1,235	$4,249	$2,394	$5,408
2031	$1,309	$29	$1,333	$4,578	$2,672	$5,916
2032	$1,520	$33	$1,459	$5,008	$3,013	$6,562
2033	$1,746	$38	$1,588	$5,459	$3,372	$7,242
2034	$1,952	$43	$1,691	$5,828	$3,685	$7,823
2035	$2,203	$48	$1,825	$6,314	$4,076	$8,565
2036	$2,429	$53	$1,932	$6,711	$4,414	$9,193
2037	$2,708	$58	$2,073	$7,234	$4,839	$10,000
2038	$2,955	$63	$2,184	$7,659	$5,202	$10,678
Total PV	**$16,265**	**$357**	**$15,087**	**$51,422**	**$31,709**	**$68,044**
Annualized	**$1,323**	**$29**	**$1,227**	**$4,182**	**$2,579**	**$5,534**

[1] 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).
Source: PHMSA analysis

5.2 Value of Natural Gas Product Losses

PHMSA estimated the benefits of avoiding natural gas losses based on avoided emissions (Table 39) and projected natural gas prices over the period of analysis (Table 40).[71] PHMSA did not estimate the value of avoided losses of other gases (*e.g.*, synthetic gas, propane). As discussed in section 3.1.2, pipelines carrying these other commodities represent a very small share (0.2 percent) of the total mileage analyzed.

The average changes in natural gas losses are equivalent to 25,500 to 57,800 million cubic feet of gas, which is approximately 0.1 to 0.2 percent of the volume of natural gas delivered to customers in 2020 (27,727,489 million cubic feet; Energy Information Administration, 2021).

[71] Natural gas prices are stated in terms of their thermal energy content, so natural gas losses in Table 40 are shown in those terms as well.

Table 39: Changes in natural gas losses (MMBtu)						
Year	Gathering	Transmission	Distribution		Total	
			Lamb *et al.* (2015)	Weller *et al.* (2020)	Low[1]	High[1]
2024	-3,029,300	-71,900	-2,447,900	-6,677,600	-5,549,100	-9,778,800
2025	-4,573,100	-105,900	-4,774,900	-13,313,000	-9,453,900	-17,992,000
2026	-6,138,600	-140,100	-7,836,500	-24,517,000	-14,115,200	-30,795,700
2027	-7,726,100	-174,600	-10,379,000	-34,068,000	-18,279,700	-41,968,700
2028	-9,336,000	-209,400	-11,948,000	-40,494,000	-21,493,400	-50,039,400
2029	-10,968,500	-244,500	-12,917,000	-44,624,000	-24,130,000	-55,837,000
2030	-12,624,000	-279,900	-13,753,000	-47,312,000	-26,656,900	-60,215,900
2031	-14,303,000	-315,500	-14,567,000	-50,011,000	-29,185,500	-64,629,500
2032	-16,006,000	-351,500	-15,358,000	-52,722,000	-31,715,500	-69,079,500
2033	-17,732,000	-387,700	-16,128,000	-55,445,000	-34,247,700	-73,564,700
2034	-19,483,000	-424,200	-16,877,000	-58,180,000	-36,784,200	-78,087,200
2035	-21,258,000	-461,000	-17,612,000	-60,931,000	-39,331,000	-82,650,000
2036	-23,059,000	-498,100	-18,335,000	-63,698,000	-41,892,100	-87,255,100
2037	-24,884,000	-535,500	-19,049,000	-66,484,000	-44,468,500	-91,903,500
2038	-26,735,000	-573,200	-19,754,000	-69,289,000	-47,062,200	-96,597,200

[1] The low estimate reflects distribution emissions based on Lamb *et al.* (2015) whereas the high estimate reflects distribution emissions based on Weller *et al.* (2020).
Derived from methane emissions in Table 33, using methane content of 87.0 percent for gathering and 93.4 percent for transmission and distribution, mass conversion factor of 0.907 metric ton/ton, specific volume of 47308 cf/ton, and energy content of 1037 Btu/cf.
Negative values represent reduced natural gas losses under the proposed rule, *i.e.*, net benefits.
Source: Methane content of natural gas from EPA, 2022a; PHMSA analysis

Table 40: Benefits from avoided natural gas losses							
Year	Natural gas spot price (2020$/ MMBtu)[1]	Value of avoided losses (million 2020$) [2]					
		Gathering	Transmission	Distribution		Total	
				Lamb *et al.* (2015)	Weller *et al.* (2020)	Low[3]	High[3]
2024	$2.80	$8	$0.2	$7	$19	$16	$27
2025	$2.88	$13	$0.3	$14	$38	$27	$52
2026	$2.98	$18	$0.4	$23	$73	$42	$92
2027	$3.04	$24	$0.5	$32	$104	$56	$128
2028	$3.18	$30	$0.7	$38	$129	$68	$159
2029	$3.29	$36	$0.8	$43	$147	$79	$184
2030	$3.34	$42	$0.9	$46	$158	$89	$201
2031	$3.36	$48	$1.1	$49	$168	$98	$217
2032	$3.42	$55	$1.2	$53	$180	$109	$236
2033	$3.49	$62	$1.4	$56	$193	$119	$257
2034	$3.52	$69	$1.5	$59	$205	$129	$275
2035	$3.53	$75	$1.6	$62	$215	$139	$292
2036	$3.54	$82	$1.8	$65	$225	$148	$309
2037	$3.53	$88	$1.9	$67	$235	$157	$324
2038	$3.55	$95	$2.0	$70	$246	$167	$343
3%	**Total PV**	**$568**	**$12.4**	**$531**	**$1,809**	**$1,111**	**$2,389**
	Annualized	**$46**	**$1.0**	**$43**	**$147**	**$90**	**$194**
7%	**Total PV**	**$408**	**$9.0**	**$391**	**$1,325**	**$808**	**$1,742**
	Annualized	**$42**	**$0.9**	**$40**	**$136**	**$83**	**$179**

[1] Source: Natural gas spot prices from U.S. Energy Information Administration (2021).
[2] Positive values represent reduced natural gas losses under the proposed rule, *i.e.*, net benefits.
[3] The low estimate reflects distribution emissions based on Lamb *et al.* (2015) whereas the high estimate reflects distribution emissions based on Weller *et al.* (2020).
Source: PHMSA analysis

5.3 Safety Benefits

Earlier detection of natural gas leaks is expected to provide safety benefits in cases where the discovered leaks present a risk to life or property.

5.3.1 Identification of Safety Conditions through Enhanced Leak Detection

Section 3.2 summarizes data reported to PHMSA on the total number of leaks eliminated each year from part 192-regulated gathering and transmission systems (Figure 2) and distribution systems (Figure 3), during the period of 2015-2020. The distribution system leaks included an annual average of 42,502 leaks operators classified as hazardous according to the existing definition (in Figure 4). These data do not indicate the ways these leaks were first identified, *e.g.*, whether operators discovered them because of a scheduled survey or following a gas odor call from the public. However, it is reasonable to assume that more timely and more effective leak surveys will help detect leaks of all types, including leaks that present a risk to life or property, and monitoring and repair requirements will help reduce the risk to life or property that may develop over time with some leaks. Several studies have demonstrated that leak surveys using ALD methods are an effective way of identifying leaks up-to-then unknown to pipeline operators (Lamb et al., 2015; Weller et al., 2020; D. Zimmerle et al., 2020). In addition, a National Transportation Safety Board (NTSB) investigation into a gas distribution incident that occurred on February 23, 2018 revealed how weaknesses in leak detection procedures can result in failures to detect hazardous leaks under certain circumstances (National Transportation Safety Board, 2018).

Past incident reports lend further support to expectations that more frequent, and more effective leak surveys may yield safety benefits. PHMSA reviewed a total of 1,344 gas gathering and transmission incidents and 1,258 gas distribution incidents reported by pipeline operators during the period of 2010 through 2020. These data include only reportable incidents[72] and therefore represent only a small subset of all gas releases from pipelines and other gas facilities. Most of the incidents reported for gathering and transmission systems (1,261) were from transmission pipelines, including over 500 leaks.[73] Equipment failure, corrosion failure and material failure of pipe or weld accounted for almost two thirds of incidents (792). Since these causes are conditions that may develop over time, they may be most amenable to being discovered during leak surveys. Part 192-regulated gathering lines (Type A or B)[74] had 83 gas incidents, including 69 leaks. Seventy-one incidents were due to causes that may develop gradually and be detected during a leak survey. Incident descriptions do not consistently describe incident circumstances, but the data do indicate how the incident was first discovered. For 61 leak incidents, discovery occurred through an air patrol (31 incidents) or a ground patrol by the operator or its contractor (29 incidents). Several incident descriptions noted that patrols or instrumented surveys led to the

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[72] Following §191.3, a reportable pipeline incident is an event with one or more of the following consequences: (i) A death, or personal injury necessitating in-patient hospitalization; (ii) Estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost; (iii) Unintentional estimated gas loss of three million cubic feet or more; or an event that is significant in the judgment of the operator, even though it did not meet other applicability criteria.

[73] Other types of incidents include mechanical puncture, rupture, and other.

[74] Incidents from regulated Type C gathering lines did not need to be reported during the data period.

discovery of leaks, for example by noticing bubbles in the vicinity of a transmission pipeline. For two incidents, the incident description specifically mentioned a line having been patrolled or surveyed prior to the incident. One incident was identified during a “30-day leak follow-up inspection” of the same pipeline segment. In the other incident, the leak was discovered on a line that had been recently patrolled, which led the operator to conclude along with visual evidence on the ground that the leak occurred more recently (the description did not provide the elapsed time since the patrol). In another incident, a second separate leak was discovered by company personnel patrolling the pipeline as part of follow-up on a first leak.

Similarly, gas distribution operators attributed incidents reported to PHMSA to one of four release types: leaks, mechanical punctures, ruptures, and “other.” Overall, pipeline leaks accounted for 31 percent of all release types (377 incidents). Excavation damage and other outside force damage were by far the most common causes of distribution incidents, accounting for almost two thirds of reported incidents. While more frequent or better leak surveys may not help prevent these types of incidents, they may be helpful in cases where damage is minimal and undiscovered until later when a leak or hazardous conditions develop. Corrosion failure, equipment failure and material failure of pipe or weld, conditions that develop over time and therefore may be the most amenable to detection through periodic leak surveys, accounted for 14 percent of all incidents. Of the leak incidents, the most common causes were “other” (35 percent), which encompassed a wide variety of incident circumstances. Most were sudden and may not be preventable through more frequent or better leak surveys. Out of a total of 377 leak incidents, 55 were attributed to natural forces (*e.g.*, lightning, heavy rain), which shows the utility of extreme weather-related leak surveys. Leaks leading to reportable incidents were most often discovered via notification from emergency responder (54 percent), local operating personnel (21 percent), and notification from the public (16 percent), but there were at least 16 incidents for which the incident narrative specifically mentioned that the incident was discovered during a scheduled leak survey by operator or contractor personnel.[75]

5.3.2 Potential Prevention of Safety Conditions

There is no way to ascertain how many more leaks hazardous to life or property may be discovered through more frequent and more effective pipeline surveys and repaired as a result of the proposed rule. For this analysis, PHMSA estimated the changes in the mileage of pipelines surveyed each year under the proposed rule (see Table 23) and the additional leaks discovered during these surveys (see Table 14 and Table 26). In the case of gathering and transmission lines, an unknown share of these 29,051 discovered leaks (see Table 14) may be determined to be hazardous. For distribution pipelines, assuming uniform leak incidence rates per pipe material and a constant share of leaks classified in each grade based on the current definitions, PHMSA estimated that approximately 17,700 to 25,100 more leaks hazardous to life or property may be discovered on average per year through more frequent surveys and more effective survey methods. This estimate is based on the annual average incremental number of leaks detected under the proposed rule, as compared to the baseline, and the assumption that 40 percent of all leaks are categorized in grades 1 and 2, following the baseline definitions, as discussed in section

[75] Incident narratives generally did not provide details on survey or maintenance practices.

4.2.2. PHMSA estimated the increase to be largest in the early years of the analysis period as operators transition to shorter survey intervals.

The benefits of repairing these leaks earlier include avoided deaths, injuries, evacuations, and property and environmental damages. As illustration of the potential consequences of gas leaks and other types of incidents, Table 41 summarizes PHMSA data on reported pipeline incidents by industry segment and release type during the period of 2010-2020. The average cost per incident was $1.7 million for gathering, $1.2 million for transmission, and $2.1 million for distribution. Incidents categorized as leaks tended to release smaller quantities of gas, on average, than those categorized as mechanical puncture or rupture. However, they were still significant both individually and in total, given their frequency. Incidents caused by leaks accounted for the largest aggregate volume of gas released in gathering incidents. For transmission pipelines, leaks were second only to incidents due to rupture, whereas for distribution pipelines, leaks were second to incidents due to mechanical puncture. The average damage costs reported to PHMSA due to a leak was $373,000 to $395,000 per incident. The average cost in Table 41 accounts only for costs directly incurred by operators and does not include other costs to society. The total social costs of these incidents can be much larger, particularly where fatalities and injuries are involved. For example, the 140 fatalities due to gas pipeline incidents between 2010 and 2020 have social costs estimated at $1.6 billion.[76] Including the 647 non-fatal injuries associated with the incidents and assuming that each injury was serious brings the total value of injuries and fatalities to $2.4 billion.[77]

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[76] Calculated using DOT's Value of a Statistical Life of $11.6 million in 2020 (U.S. Department of Transportation, n.d.).

[77] Injuries were monetized using DOT's recommended disutility factor for serious injuries (Maximum Abbreviated Injury Scale (MAIS) 3 = 0.105) times the VSL estimate. Department of Transportation, 2021

Table 41: Damages and costs from reported gas pipeline incidents in 2010-2020									
Industry Segment	**Release type**	**Total number of incidents**	**Number of incidents with injuries or fatalities**	**Number of Fatalities**	**Number of Injuries**	**Average volume of gas released (Mcf)[1]**	**Total Volume of Gas Released (Mcf)**	**Average cost (2020$)[2]**	**Value of Injuries and Fatalities (2020$)[3]**
Gathering	Leak	69	1	0	1	4,861	320,803	$395,190	$1,218,000
	Mechanical puncture	2	0	0	0	12,680	12,680	$3,079,639	$0
	Rupture	5	0	0	0	26,830	134,148	$1,686,308	$0
	Other	7	0	0	0	15,067	90,401	$14,466,256	$0
	All types	**83**	**1**	**0**	**1**	**7,154**	**558,031**	**$1,724,370**	**$1,218,000**
Transmission	Leak	500	5	1	7	11,890	5,921,329	$373,076	$20,126,000
	Mechanical puncture	126	6	6	13	11,718	1,476,521	$408,945	$85,434,000
	Rupture	169	8	10	75	52,136	8,811,065	$5,942,098	$207,350,000
	Other	466	11	10	13	15,196	6,914,321	$592,805	$131,834,000
	All types	**1,261**	**30**	**27**	**108**	**18,528**	**23,123,236**	**$1,207,637**	**$444,744,000**
Distribution	Leak	377	98	28	182	1,355	444,437	$394,395	$546,476,000
	Mechanical puncture	356	53	15	96	2,150	743,960	$463,367	$290,928,000
	Rupture	55	17	7	19	1,847	97,870	$229,763	$104,342,000
	Other	421	119	63	241	979	326,920	$5,425,612	$1,024,338,000
	All types	**1,209**	**287**	**113**	**538**	**1,520**	**1,613,187**	**$2,121,050**	**$1,966,084,000**

[1] Estimated volume of gas released unintentionally and intentionally (during controlled release or blowdown). The average includes only incidents with non-zero reported volumes released.
[2] Estimated costs of the release, including property damage, repairs, emergency response, value of gas lost, and other costs incurred by operators. The average includes only incidents with non-zero reported costs.
[3] Estimated value of injuries and fatalities based on VSL (U.S. Department of Transportation, n.d.) and DOT's recommended disutility factor for serious injuries (Maximum Abbreviated Injury Scale (MAIS) 3 = 0.105; Department of Transportation, 2021)
Source: PHMSA Pipeline Incident Flagged Files, June 30, 2021

The severity of human safety and property damages depends principally on the leak rate and location. Population density and proximity to buildings and other structures are critical factors. As summarized in Table 41, injuries or fatalities occurred in approximately a quarter of the reported distribution incidents. While injuries and fatalities were less frequent for gathering and transmission incidents, they were reported for 31 incidents during the 11-year period, with a total of 140 fatalities.

Due to the difficulty of predicting the probability of the leaks estimated above to result in injuries, fatalities, or other damages and the severity of the damages, PHMSA did not monetize the safety benefits of the proposed rule but notes that these benefits could be significant. PHMSA is requesting comments and data that would better enable quantification and monetization of the health and safety benefits of the proposed rule, such as information needed to model exposure levels and duration.

PHMSA also expects safety benefits from expanded NPMS reporting requirements for gathering lines, although these benefits are difficult to quantify. The requirement to submit data to the NPMS will support operators with developing and maintaining adequate maps and records of their systems. Pipeline safety stakeholders — including the public, emergency responders, excavators, and elected officials — use the NPMS to view the locations of pipelines and related infrastructure, identify the names and contact information of pipeline operators, and understand other attributes of pipelines such as commodities transported and diameter. For example, emergency responders often use the NPMS to identify pipelines in the vicinity of reported leaks and to contact relevant operators. NPMS data can also make it easier for third parties such as other operators, researchers, or the public to report leaks, ruptures, and other unsafe conditions to the appropriate operator.

5.4 Other Health Benefits

PHMSA also expect additional human health benefits from reducing emissions of volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) contained in natural gas, particularly unprocessed natural gas in gathering lines.[78] As discussed at greater length in EPA (2022b), 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 (U.S. EPA, 2019; 2022d). HAPs contained in unprocessed natural gas includes several substances, including but not limited to benzene, formaldehyde, toluene, xylenes, and ethylbenzene, that are known or suspected carcinogens or have other adverse health effects (U.S. EPA, 2022c).

Benzene is a known human carcinogen (causing leukemia) and chronic (long-term) inhalation has been associated with several adverse noncancer health effects including arrested development of blood cells, anemia, leukopenia, thrombocytopenia, and aplastic anemia (Agency for Toxic Substances and Disease Registry [ATSDR], 2007a; U.S. EPA, 2012). Acute (short-

[78] While VOCs and HAPs have mostly been documented in unprocessed natural gas transported in gathering lines, some studies suggest that they are also present within the transmission, storage and distribution segments (Michanowicz *et al.*, 2022; Nordgaard *et al.*, 2022).

term) exposure to benzene vapors has been reported to cause respiratory effects such as nasal irritation, mucous membrane irritation, dyspnea, and sore throat.

Formaldehyde is classified by the National Toxicology Program (NTP) as known to be a human carcinogen based on sufficient evidence of cancer from studies in humans supporting data on mechanisms of carcinogenesis (NTP, 2021). Formaldehyde inhalation exposure causes a range of noncancer health effects including irritation of the nose, eyes, and throat in humans and animals. Repeated exposures cause respiratory tract irritation, chronic bronchitis and nasal epithelial lesions such as metaplasia and loss of cilia in humans, whereas there is evidence that formaldehyde may increase the risk of asthma and chronic bronchitis in children (ATSDR, 1999; U.S. EPA, 2000b).

Toluene has been shown to affect the central nervous system under acute and chronic exposures with low or moderate levels of toluene exposure by inhalation causing fatigue, sleepiness, headaches, and nausea (U.S. EPA, 2005a; 2005b). Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep. Human studies have also reported developmental effects from toluene exposure, such as central nervous system dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (*i.e.*, impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

Short-term inhalation of mixed xylenes in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects (U.S. EPA, 2000c). Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys (ATSDR, 2007b). Long-term inhalation exposure to xylenes in humans has been associated with a number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination (ATSDR, 2007b). The EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity (U.S. EPA, 2000c).

Acute exposure to ethylbenzene results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic exposure to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood (U.S. EPA, 2000a). EPA has classified ethylbenzene as a Group D, not classifiable as to human carcinogenicity. However, on the basis of chronic inhalation bioassay in mice and rats conducted by NTP, the International Agency for Research on Cancer (IARC) classified ethylbenzene as Group 2B, possibly carcinogenic to humans (ATSDR, 2010).

PHMSA found no national estimate of VOC and HAP emissions released from gas pipelines. Emissions rates vary according to the production region, emissions sources (*e.g.*, well head, condensate tanks, engine exhausts), and other factors (Lebel *et al.*, 2022; Michanowicz *et al.*, 2022; Nordgaard *et al.*, 2022). EPA (2022b) estimated that reducing fugitive methane emissions from well sites and gathering and boosting stations also reduced associated emissions of VOCs and HAPs, with each short ton of methane avoided corresponding to 0.28 short ton VOC and 0.01 short ton HAP avoided. PHMSA did not quantify the magnitude of these benefits in this analysis but notes that the impacts of these pollutants accrue at different spatial scales. HAP emissions increase exposure to carcinogens and other toxic pollutants primarily near the emission source, and therefore a detailed analysis would need to account for the location of the gathering lines relative to exposed populations as well as the duration and magnitude of exposure. VOC emissions are precursors to secondary formation of $PM_{2.5}$ and ozone on a broader regional scale, requiring air quality modeling to assess changes in ambient concentrations. Methane is also a precursor to global background concentrations of ozone and reducing methane emissions is therefore expected to also reduce global background ozone concentrations that contribute to the incidence of ozone-related health effects (U.S. Global Change Research Program, 2018a). Due to data limitations regarding the location, magnitude, and duration of exposure and the quantitative relationship between exposure and incidence of health effects, PHMSA did not quantify these benefits. PHMSA requests data and comments on the potential human health benefits from reducing emissions of volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) resulting from the proposed rule, including information that would help address these data limitations and better enable quantification and monetization of the potential human health benefits.

5.5 Total Monetized Benefits

Table 42 summarizes the total monetized benefits of the proposed rule. PHMSA estimates annualized benefits ranging between $1,081 million and $2,320 million using a 3-percent discount rate ($1,073 million and $2,304 million using a 7-percent discount rate). Table 68 presented later in section 8.1 compares these benefits to the costs that were summarized in Table 31 and presents the estimated net benefits of the proposed rule.

The monetized benefits do not provide a full account of all expected benefits of the proposed rule. Additional unmonetized benefits include safety benefits, prevented releases of gases other than methane, and avoided loss of products other than natural gas.

Table 42: Annualized monetized benefits (million 2020$)

Discount Rate	Methane emissions reduction		Avoided natural gas losses		Total monetized benefits[1,2]	
	Low[3]	High[3]	Low[3]	High[3]	Low[3]	High[3]
3%	$990	$2,126	$90	$194	**$1,081**	**$2,320**
3% and 7%[4]	$990	$2,126	$83	$179	**$1,073**	**$2,304**

[1] Total may not add up due to independent rounding.
[2] The total does not include additional benefits of reducing methane releases, benefits of reducing releases of other gases, and safety benefits.
[3] The low estimate reflects distribution benefits based on Lamb *et al.* (2015) whereas the high estimate reflects distribution benefits based on Weller *et al.* (2020).
[4] Climate benefits are discounted at 3 percent based on the average SC-CH_4 at 3 percent discount, whereas benefits from avoided natural gas losses are discounted at 7 percent. See section 5.1.3 for climate benefits using other discount rates.
Source: PHMSA analysis

5.6 Uncertainty and Limitations

Table 43 highlights the principal sources of uncertainties and limitations present in the benefits analysis. Where feasible, the table notes the direction of any resulting bias in the estimation of benefits (*i.e.*, whether the assumption PHMSA made for the analysis results in benefits being over- or understated, all else being equal).

Table 43: Principal sources of uncertainty in the benefits analysis.

Item	Sources of uncertainty	Direction of the impact
Environmental and health benefits of reductions in tropospheric ozone levels	PHMSA did not quantify the environmental and human health benefits from reductions in ground-level ozone levels resulting from reductions in emissions of methane and other gases.	Understate benefits
Leak incidence rates and emission factors	The estimated emissions are sensitive to the assumed leak incidence rates and emission factors. For distribution, PHMSA used average rates from published studies (*i.e.*, Lamb et al., 2015; Weller et al., 2020) that reflect the sensitivity of methane leak detection methods and conditions at the time each study was conducted. PHMSA presents estimates as a range to reflect the uncertainty suggested by differences across studies. For gathering and transmission, PHMSA derived methane emission factors by combining data on leaks reported to PHMSA and emissions estimates from the GHGI (EPA, 2022e). The estimates reflect a distribution of methane leaks that range from the smallest leaks researchers detected during the survey to so-called "super emitters." PHMSA assumed that modeled methane leaks follow a similar distribution. Actual emissions may differ from those calculated based on the emission factors.	Direction unknown
	PHMSA uses static emission factors that are specific to each material and gas but do not change over the period of analysis as a function of the pipe age or other characteristics. PHMSA accounted for trends in the mileage of distribution mains by materials to capture some of the effects of replacing leak-prone pipes, but this captures only some of the leak reduction benefits of upgrading leak-prone and vintage pipelines. Leak incidence rates may increase as existing pipes age or may be less as pipes are replaced or repaired.	Direction unknown
	In the absence of studies focused on non-natural gas pipelines, PHMSA assumed that pipelines transporting landfill gas and synthetic gas have the same leak incidence rates as those transporting natural gas, and equivalent emission factors when adjusting for differences in the methane content of landfill gas and synthetic gas as compared to natural gas. In fact, pipelines transporting commodities other than natural gas (*e.g.*, pipelines transporting hydrogen or hydrogen blends) may have lower or higher leak incidence and emissions rates.	Direction unknown
Attribution of avoided methane emissions of the proposed rule	The proposed rule is estimated to result in a greater number of leaks identified due to the requirement to employ more effective leak detection methods. The analysis attributes all incremental emission reductions to the proposed rule even though repairs of leaks determined to be hazardous are already required under the baseline requirements.	Overstate benefits
Social cost of methane values	The bulk of the annualized benefits of the proposed rule consists of the climate benefits from avoiding methane emissions, which are monetized using the social cost of methane (SC-CH_4). Because greenhouse gases are long-lived and subsequent damages of current emissions can occur over a long time, the approach to	Direction unknown

Table 43: Principal sources of uncertainty in the benefits analysis.		
Item	**Sources of uncertainty**	**Direction of the impact**
	discounting greatly influences the present value of future damages. Table 34 and Figure 6 illustrate the variability of SC-CH_4 values for different discount rates. Modeling assumptions may also affect SC-CH_4 values. Draft SC-CH_4 values presented in EPA's September 2022 *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* (EPA, 2022b) reflect recent advances in the scientific literature on climate change and its economic impacts and incorporate recommendations made by the National Academies (National Academies of Sciences, 2017b). The Academies' recommendations for updating estimates of the social cost of carbon included specific criteria for future updates to the estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs for multiple components of the estimation process (National Academies of Sciences, 2017b). The updated SC-CH_4 estimates reflect methodological improvements in all four components of the social cost of greenhouse gas estimation process: socioeconomics and emissions, climate, damages, and discounting. EPA (2022b) provided SC-CH_4 estimates for near-term Ramsey discount rates of 2.5 percent, 2 percent, and 1.5 percent.[79] The climate benefits of methane emission reductions under the proposed rule using these alternative sets of SC-CH_4 estimates would produce larger net benefits, owing in part to the lower discount rates.	
Gas odorization	PHMSA assumed that *intrastate* Class 3 and Class 4 natural gas transmission lines are odorized, and all other lines (*e.g.*, all interstate lines, intrastate lines in Class 1 and 2, gathering lines, and lines that transport commodities other than natural gas) are not odorized. The rule requirement increases the frequency of surveys for a subset of odorized lines that are either leak prone or in an HCA. To the extent that more lines are odorized and are either leak prone or in an HCA, then the analysis understates the additional number of surveys conducted and leaks discovered.	Understate benefits
Extension of leak remediation timeline	PHMSA assumed that it would receive requests from distribution operators to extend the deadline for remedying leaks but did not account for the associated delays when modeling the number of repairs that may be completed each year and the associated avoided emissions. PHMSA does not have information to estimate when these leaks would be repaired. To the extent that some repairs would be delayed in the proposed rule scenario beyond the analyzed schedule, benefits may be overstated.	Overstate benefits
Emissions of VOC and HAPs	For natural gas gathering lines, PHMSA also expects additional human health benefits from reducing emissions of VOCs and HAPs contained in unprocessed natural gas.	Understate benefits

Table 43: Principal sources of uncertainty in the benefits analysis.		
Item	**Sources of uncertainty**	**Direction of the impact**
Benefits associated with repairing leaks on pipelines transporting flammable, toxic, and corrosive gasses other than natural gas	PHMSA's quantification of benefits does not consider avoided loss of products other than natural gas or avoided environmental impacts of emissions other than methane. PHMSA also expects additional human health and environmental benefits from reduced emissions of flammable, toxic, and corrosive gases other than natural gas (including, but not limited to, hydrogen gas and hydrogen gas blends). In particular, PHMSA notes current commercial interest in gas pipelines transporting hydrogen and hydrogen blends. However, PHMSA currently regulates only a small (ca. 1,500 miles) amount of existing hydrogen pipelines, and future demand for additional hydrogen pipelines has not yet materialized into a substantial number of near-term projects.	Understate benefits
Effectiveness of commercially available advanced leak detection technology and practices for leak detection and investigation in connection with gas pipelines transporting flammable, toxic, and corrosive gasses other than natural gas	PHMSA's quantification of benefits does not consider the effectiveness of commercially available advanced leak detection and practices for leak detection and investigation in connection with gas pipelines transporting flammable, toxic, and corrosive gasses other than natural gas. PHMSA acknowledges that such leak detection technologies and practices for each flammable, toxic, and corrosive gas subject to the proposed rule may be more or less effective than commercially available advanced leak detection technology and practices for methane leaks from natural gas pipelines.	Direction unknown
Environmental impacts of conducting leak surveys	PHMSA did not include certain disbenefit to society in the form of environmental and other impacts of conducting surveys (*e.g.*, increased fuel combustion). These impacts are expected to be small relative to the overall benefits from avoided emissions.	Overstate benefits

6 Uncertainty Analysis and Regulatory Alternatives

As discussed throughout the PRIA, multiple parameters affect the estimated costs and/or benefits of the proposed rule but are uncertain. This section provides PHMSA's quantitative analysis of uncertainty by evaluating the sensitivity of the costs and/or benefits of the proposed rule to varying modeling assumptions for selected parameters (sections 6.1 through 6.5). These parameters include the assumed baseline for the proposed rule (section 6.1), leak incidence rates and emission factors (section 6.2), leak survey effectiveness (section 6.3), and leaks from distribution services (section 6.4). Overall, across the range of sensitivity analyses PHMSA conducted, the proposed rule provides net benefits.

The section also provides estimated costs and benefits for two regulatory alternatives PHMSA considered for distribution systems (section 6.5).

6.1 PIPES Act of 2020 Self-Implementing Provisions (Alternative Baseline Analysis)

As discussed in section 2.1.4 of this PRIA, the baseline for this analysis reflects requirements under existing laws and regulations including the PIPES Act of 2020. PHMSA also evaluated the proposed rule relative to a pre-statutory baseline, in part because of uncertainty regarding the effects of self-implementing provisions of the PIPES Act of 2020.

6.1.1 Costs of Self-implementing Provisions of the PIPES Act of 2020

In Section 114 of the PIPES Act, Congress imposed a self-executing mandate obliging operators of gas pipeline facilities — including gas transmission, distribution, and gathering — to update their procedures to minimize the release of natural gas from their facilities. To facilitate operator implementation of the self-executing mandate, PHMSA proposes to incorporate that statutory language within the Pipeline Safety Regulations. Specifically, PHMSA proposes to require gas transmission, distribution, offshore gathering, and Type A gathering pipeline operators to minimize the release of gas to the environment from intentional, vented emissions such as blowdowns.[80]

As discussed in section 3.5, implementation of mitigation practices to reduce blowdown emissions is considered part of the baseline and therefore not attributed to this proposed rule. In addition, the costs of blowdown mitigation depend on the practices chosen, baseline blowdown activity, current mitigation practices, and the level of implementation. For information purposes, PHMSA provides below an illustrative example of potential costs associated with blowdown mitigation. See section 6.1.2 for a description of the associated benefits.

PHMSA reviewed operator reports to estimate the unit costs ($/mile) of preventing or mitigating blowdown emissions. Specifically, PHMSA reviewed reported costs of blowdown mitigation

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80 PHMSA also proposes to require LNG facilities and UNGSFs to minimize intentional, vented emissions. PHMSA did not include the additional costs or benefits of avoided blowdown emissions from LNG facilities and UNGSFs in this analysis.

programs implemented by SoCal and PG&E to estimate unit costs per mile.[81] Table 44 summarizes the estimated capital and O&M unit costs by pipeline segment. Due to the lack of available data, PHMSA was unable to estimate unit costs specific to gathering lines and therefore applied the transmission unit costs to gathering lines as well. PHMSA requests comment on these assumptions and estimates, including any additional supporting data.

Table 44: Unit costs for blowdown mitigation practices		
Pipeline Segment	**Capital (2020$ per mile)**	**O&M (2020$ per mile)**
Gathering and boosting	$590	$236
Transmission	$590	$236
Distribution	$231	$595
Source: California Public Utilities Commission, 2018, Southern California Gas Company, 2020		

PHMSA assumed that all operators not currently implementing blowdown mitigation measures, based on reported participation in EPA's voluntary Natural Gas STAR program, would incur the same unit costs. This is a simplifying assumption. As described above, actual costs depend on blowdown activity level, mitigation practices, and level of implementation (*i.e.*, the share of blowdown events on which mitigation practices are implemented). Table 45 summarizes potential costs associated with blowdown mitigation.[82] PHMSA assumed that capital costs would be a one-time cost in the first year of the analysis, and O&M costs would be incurred annually over the analysis period.

Table 45: Costs for blowdown mitigation, by pipeline segment (million 2020$)			
Year	**Gathering[1]**	**Transmission**	**Distribution**
2024	$8.7	$226	$692
2025	$3.2	$81	$505
2026	$3.4	$82	$512
2027	$3.5	$82	$518
2028	$3.6	$83	$524
2029	$3.8	$84	$531
2030	$3.9	$85	$537
2031	$4.1	$86	$544
2032	$4.2	$86	$550
2033	$4.4	$87	$557
2034	$4.6	$88	$563
2035	$4.7	$89	$570
2036	$4.9	$90	$577
2037	$5.1	$90	$583
2038	$5.2	$91	$590

81 Information included SoCal Gas's loaded costs of "minimizing blowdown in transmission" and "gas capture centralized organization" and PG&E's capital and expense costs for "implementation of best practices" for blowdown reductions for distribution and transmission. PHMSA divided these total program costs by the corresponding mileage to obtain unit costs per mile.

82 These provisions apply only to Type A gathering lines and PHMSA therefore estimated costs and benefits based only on Type A gathering line mileage. In addition, PHMSA assumed that operators would implement blowdown mitigation practices on pipelines transporting all commodities, but monetized benefits only for natural gas pipelines (as presented in section 6.1.2).

Table 45: Costs for blowdown mitigation, by pipeline segment (million 2020$)				
Year		Gathering[1]	Transmission	Distribution
3%	**Total PV**	**$55.1**	**$1,192**	**$6,836**
	Annualized	**$4.5**	**$97**	**$556**
7%	**Total PV**	**$43.8**	**$970**	**$5,415**
	Annualized	**$4.5**	**$100**	**$556**
[1] Based on mileage of Type A regulated gathering lines. *Source: PHMSA analysis*				

6.1.2 Benefits from Self-implementing Provisions of the PIPES Act of 2020

There are additional benefits from mitigating releases of natural gas during venting and blowdown. As discussed in section 3.5, implementation of mitigation practices is considered part of the baseline and therefore not attributed to this proposed rule.

For information purposes, PHMSA provides an illustrative example of potential benefits associated with blowdown mitigation practices, consistent with the scenario used to estimate costs in section 6.1.1.[83] To estimate baseline blowdown emissions, PHMSA relied on methane emissions factors from EPA's GHGI, as summarized in Table 46. To estimate baseline blowdown emissions, PHMSA applied the emissions factor to pipeline mileage for operators not currently implementing blowdown mitigation practices, based on participation in EPA's voluntary Natural Gas STAR program. Of the 2,274 operators included in this analysis, 2,204 are not listed Natural Gas STAR program participants and were therefore assumed not to implement blowdown mitigation practices in the pre-statutory baseline used for this analysis.

Table 46: Estimated blowdown emissions in 2020		
Pipeline segment	CH_4 emissions (metric ton CH_4)	CH_4 emissions factor (kg/mile)
Gathering and boosting	9,390	21.4
Transmission	221,278	732.8
Distribution	2,093	0.9
Source: U.S. EPA, 2022e		

PHMSA relied on the same operator reports to estimate the percentage reduction in blowdown emissions, as compared to the baseline (Table 47). These emissions reductions are associated with the unit cost reported in Table 44. Like the analysis of costs, actual benefits resulting from blowdown mitigation practices will depend on the mitigation practices chosen, baseline blowdown activity, current mitigation practices, and the level of implementation. In addition, the lack of data prevented PHMSA from estimating emissions reductions specific to gathering lines and PHMSA therefore applied the transmission emissions reduction estimate to those lines as well.

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83 PHMSA estimated that eliminating *all* methane emissions from venting and blowdown of gathering, transmission, and distribution pipelines — 232,761 MMTon CH_4 (EPA, 2021a; EPA, 2022e) — could generate annualized benefits over the analysis period of $496 million per year, using a 3 percent discount rate. These annualized benefits consist of $453 million from the avoided methane emissions and $43 million from the avoided natural gas losses and represent an upper bound estimate of potential benefits.

Table 47: Estimated blowdown emissions reduction	
Pipeline Segment	**% reduction**
Gathering and boosting	43.4%
Transmission	43.4%
Distribution	8.2%
Source: Southern California Gas Company, 2020, Pacific Gas and Electric Company, 2020a, Pacific Gas and Electric Company, 2022	

Table 48 presents the avoided blowdown emissions, by segment, assuming the percentage reductions presented in Table 47 are achieved in each year of the analysis period. In assessing avoided blowdown methane emissions, PHMSA considered emissions from natural gas pipelines only. Since the bulk of estimated baseline blowdown emissions are associated with transmission lines, total avoided blowdown methane emissions represent approximately 43 percent of baseline blowdown emissions.

Table 48: Avoided blowdown methane emissions (metric ton CH_4)				
Year	**Gathering**	**Transmission**	**Distribution**	**Total**
2024	2.4	96,857	104	96,963
2025	2.5	97,587	105	97,694
2026	2.6	98,321	106	98,429
2027	2.7	99,059	107	99,169
2028	2.8	99,828	108	99,939
2029	2.9	100,647	109	100,759
2030	3.1	101,469	110	101,583
2031	3.2	102,293	112	102,408
2032	3.3	103,121	113	103,237
2033	3.4	103,949	114	104,066
2034	3.6	104,777	115	104,895
2035	3.7	105,619	116	105,739
2036	3.8	106,470	117	106,592
2037	3.9	107,327	119	107,449
2038	4.1	108,188	120	108,312
Source: PHMSA analysis				

PHMSA estimated the benefits of avoided methane emissions and natural gas losses based on the social cost of methane (see 3 percent discount rate values in Table 34) and projected prices at Henry Hub (see Table 40). Table 49 and Table 50 present the climate benefits of avoided methane emissions and benefits from avoided natural gas losses, respectively, by segment.

Table 49: Climate benefits of avoided methane emissions (million 2020$)				
Year	**Gathering**	**Transmission**	**Distribution**	**Total**
2024	$0.004	$165	$0.18	$165
2025	$0.005	$176	$0.19	$176
2026	$0.005	$177	$0.19	$177
2027	$0.005	$188	$0.20	$188
2028	$0.005	$190	$0.21	$190
2029	$0.006	$201	$0.22	$202
2030	$0.006	$203	$0.22	$203
2031	$0.007	$215	$0.23	$215
2032	$0.007	$217	$0.24	$217
2033	$0.008	$229	$0.25	$229
2034	$0.008	$231	$0.25	$231
2035	$0.008	$243	$0.27	$243
2036	$0.009	$245	$0.27	$245

Table 49: Climate benefits of avoided methane emissions (million 2020$)					
Year		Gathering	Transmission	Distribution	Total
2037		$0.009	$258	$0.28	$258
2038		$0.010	$260	$0.29	$260
3%	**Total PV**	**$0.080**	**$2,573**	**$2.80**	**$670**
	Annualized	**$0.007**	**$209**	**$0.23**	**$55**
Source: PHMSA analysis					

Table 50: Benefits from avoided natural gas losses (million 2020$)					
Year		Gathering	Transmission	Distribution	Total
2024		$0.000	$16	$0.02	$16
2025		$0.000	$16	$0.02	$16
2026		$0.000	$17	$0.02	$17
2027		$0.001	$17	$0.02	$17
2028		$0.001	$18	$0.02	$18
2029		$0.001	$19	$0.02	$19
2030		$0.001	$20	$0.02	$20
2031		$0.001	$20	$0.02	$20
2032		$0.001	$20	$0.02	$20
2033		$0.001	$21	$0.02	$21
2034		$0.001	$21	$0.02	$21
2035		$0.001	$22	$0.02	$22
2036		$0.001	$22	$0.02	$22
2037		$0.001	$22	$0.02	$22
2038		$0.001	$22	$0.02	$22
3%	**Total PV**	**$0.005**	**$238**	**$0.26**	**$238**
	Annualized	**$0.000**	**$19**	**$0.02**	**$19**
7%	**Total PV**	**$0.004**	**$185**	**$0.20**	**$185**
	Annualized	**$0.000**	**$19**	**$0.02**	**$19**
Derived from methane emissions in Table 48, using methane content of 87.0 percent for gathering and 93.4 percent for transmission and distribution, mass conversion factor of 0.907 metric ton/ton, specific volume of 47308 cf/ton, and energy content of 1037 Btu/cf. *Source: Methane content of natural gas from EPA, 2022a; PHMSA analysis*					

Table 51 presents the total annualized monetized benefits of the blowdown mitigation scenario.

Table 51: Annualized monetized benefits (million 2020$)			
Discount Rate	Climate benefits	Avoided natural gas losses	Total monetized benefits
3%	$209	$19	$229
7%[1]	$209	$19	$229
[1] Costs and benefits of natural gas losses are discounted at 7 percent, whereas climate benefits are discounted at 3 percent based on the average SC-CH_4 at 3 percent discount. See section 5 for estimated climate benefits using other discount rates. *Source: PHMSA analysis*			

6.1.3 Costs and Benefits of the Proposed Rule Relative to a Pre-Statutory Baseline

Table 52: Total annualized costs and benefits of the proposed rule relative to a pre-statutory baseline (million 2020$, at 3 percent discount)						
Rule element	**Annualized costs**		**Annualized benefits[1]**		**Net benefits**	
Blowdown emissions	$657		$229		-$429	
	Low[2]	High[2]	Low[2]	High[2]	Low[2]	High[2]
Other requirements	$738	$878	$1,061	$2,301	$324	$1,423
Proposed rule total	**$1,395**	**$1,535**	**$1,290**	**$2,530**	**-$105**	**$995**

[1] Climate benefits based on estimate developed by IWG of the average SC-CH_4 at 3 percent discount.
[2] The range reflects different leak incidence rates and emission factors for distribution pipelines. For the low estimate, distribution costs and benefits are based on distribution leak incidence rates and emission factors from Lamb *et al.* (2015). For the high estimate, distribution costs and benefits are based on distribution leak incidence rates and emission factors from Weller *et al.* (2020).
Source: PHMSA analysis

6.2 Gathering Pipeline Leak Incidence Rate and Emission Factor

The estimated costs and benefits of the rule are sensitive to leak incidence rates as these rates determine the number of discoverable leaks and repairs. The benefits are additionally sensitive to the assumed emission factors. The main analysis includes a range of values for distribution pipelines based on alternative estimates of leak incidence and emissions rates from the literature. There is comparably less available data to characterize leaks from gathering and transmission pipelines. This section provides the results of a sensitivity analyses using alternative leak incidence and emission factor assumptions for certain gathering lines.

For the main analysis detailed in the PRIA, PHMSA used a baseline leak incidence rate derived based on the number of leaks and total pipeline mileage reported in PHMSA annual reports (2015-2020 average) and a leak emissions rate based on the methane emission factors for gathering and boosting pipeline leaks (288.5 kg/mile) from EPA's GHGI. PHMSA also estimated the costs and benefits using emission factors from recent field surveys indicating varying rates of methane emissions across U.S. oil and gas production areas. For example, two studies of leaks in the Permian Basin in West Texas and southeastern New Mexico provide alternative methane emission factors:

- The Environmental Defense Fund (EDF) Permian Methane Analysis Project (PermianMAP) collected empirical data to pinpoint, measure and report on oil and gas methane emissions in the Permian Basin (https://www.permianmap.org/). Data for three aerial surveys (Fall 2019, Summer 2021, and Fall 2021) provide observed emissions attributed to gathering pipeline sources within the Basin. These surveys also pinpointed emissions to compressors, gas processing, and gas production tanks and wells. The PermianMAP data do not include an inventory of the equipment or assets that were surveyed, such as the total number of miles of gathering lines, and therefore PHMSA was unable to calculate leak incidence or emissions rate per mile.[84]

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84 A paper by Lyon *et al.* (2021) notes that the Delaware subarea of the Permian Basin (an area of approximately 100 miles by 100 miles) includes approximately 32,000 km of gathering lines, but the overlap between the PermianMAP study scope and the area surveyed in Lyon *et al.* (2021) is unclear.

- Chen *et al.* (2022) conducted a basin-wide airborne survey of oil and gas extraction and transportation activities in the New Mexico Permian Basin in October 2018 to January 2020. The survey spanned 35,923 km^2, 26,292 active wells, and over 15,000 km of natural gas pipelines. They measured methane emissions and pinpointed plumes back to their probable sources, including well site, gas processing plant, compressor station, storage tank, pipeline, and other/ambiguous sources.[85] For this review, PHMSA focused specifically on the subset of methane emissions attributed to pipelines. The authors attributed emissions to pipelines when they came "from a segment of the pipeline that is at least 200 meters (typical well pad diameter) away from any well sites, gas processing plant sites, compressor station sites, and storage tank sites." (page S44). When multiple sources were possible (*i.e.,* located within 200 meters of the plume center), the authors attributed emissions to assets other than pipelines. While individual well sites include some gathering lines, these are presumably small diameter intra-facility gathering lines that may not be regulated by PHMSA as transportation-related. Additionally, well site emissions may also come from compressor stations, storage tanks, and the well itself. Chen *et al.* (2022) estimated emissions attributable to pipelines at 29 ± 20 t/h. This estimate is based on 175 leaks (Table S7), which translates into an average rate of 166 kg CH_4/hr per leak. Based on the length of pipelines in the survey area (15,000 km) and assuming the survey was effective at detecting all existing pipeline leaks, the leak incidence rate is approximately 0.0188 leak/mile. The study did not provide additional information regarding the distribution of pipeline mileage by type, diameter, or other characteristics.

Table 53 summarizes data for the two studies and contrasts them to the estimates on which PHMSA based the results presented in sections 4.1, 5.1 and 5.2. The number of leaks detected in the Chen *et al.* (2022) study translates to a leak incidence rate (0.0188 leak/mile) that is consistent with and slightly lower than the incidence rate derived from PHMSA data (0.0253 leak/mile). The differences are most notable for emission rates, with Chen *et al.* (2022) indicating rates that are two orders of magnitude larger than those estimated based on EPA GHGI and PHMSA data (1,452 vs 11.4 metric tons CH_4/leak-year).

Table 53: Comparison between estimated leak incidence and emissions rate based on EPA and PHMSA data (PRIA estimate) and estimates from PermianMAP and Chen *et al.* (2022)

Metric	Main Analysis[1]	PermianMAP (Fall 2021)[2]	Chen *et al.* (2022)
Number of leaks	295	52	175
Pipeline mileage (mile)	11,659	N/A	9,321
Leak incidence (leak/mile)	0.0253	N/A	0.0188
Emissions factor (kg CH_4/mile-year)	288.5	N/A	27,256
Average emissions factor (kg CH_4/leak-hour)	1.3	121	166
Maximum emissions rate (kg CH_4/ leak-hour)	N/A	1,156	N/A
Average annual emissions rate (metric tons CH_4/leak-year)	11.4	1,058	1,452

N/A: Data unavailable.
[1] Number of leaks is average of leaks reported to PHMSA in 2015-2020. Pipeline mileage is the average PHMSA-regulated mileage in 2015-2020. Leak incidence rate is based on PHMSA incident reports divided by part 192-regulated gathering mileage. Emission factor for 2020 is from the 2022 GHGI (EPA, 2022a). Average emission factor is derived by combining the emission factor from 2022 GHGI and the leak incidence rate.
[2] Number of leaks and emission rate for the Fall 2021 survey.

[85] The study estimated emissions for "unknown" sources in cases where the source of measured plumes could not be pinpointed to known assets.

As such, using the finding from Chen *et al.* (2022) would not substantially change the number of leaks PHMSA estimated to be detected over time (and therefore the costs of making leak repairs), when compared to the main analysis, but would significantly increase the benefits from avoided gas losses and methane emissions.

As a sensitivity analysis, PHMSA applied the emission factors for gathering pipelines from Chen *et al.* (2022) to regulated gathering lines in Texas and New Mexico, using these states as a proxy for gathering lines in the Permian Basin. Specifically, PHMSA applied the emission factors from Chen *et al.* (2022) to Type A and Type B gathering mileage associated with operators in Texas and New Mexico. PHMSA estimated a corresponding share of Type C gathering pipelines (43 percent of total mileage) consists of pipelines in Texas and New Mexico that have the same alternative emission factors. PHMSA applied the emission factor used in the main analysis to gathering pipelines in other states (57 percent of total mileage). Using smaller emission factors in other production areas is consistent with comparative assessments that highlight significant variability in production-normalized methane emissions across production areas of the United States (Alvarez et al., 2018; Omara et al., 2018) and show consistently small leak incidence rates. For example, an aerial and ground-based survey by Li *et al.* (2020) of gathering pipelines in the Utica shale production area found one leak for 73 km of pipelines surveyed, with the leak coming from an accessory block valve. This low leak incidence rate was consistent with an earlier survey of the Fayetteville shale production area (D. J. Zimmerle *et al.*, 2017).

Table 54 summarizes the costs and benefits of gathering line requirements estimated using emission factors from Chen *et al.* (2022) for gathering pipelines in Texas and New Mexico and from the 2022 GHGI for other pipelines. For comparison, the table also repeats estimates detailed in sections 4.1, 5.1 and 5.2. The changes result in slightly lower costs for repairs, following the smaller leak incidence (0.0188 vs. 0.0253 leak/mile) for a subset of gathering lines, and significantly greater benefits. The much higher benefits are consistent with the two order of magnitude larger emission factor (1,452 vs. 11.4 metric tons CH_4/leak-year) for the subset of gathering lines in Texas and New Mexico.

Table 54: Costs and benefits of proposed gathering line requirements using alternative emission factors from the Permian Basin for lines in Texas and New Mexico

Results		Annualized costs or benefits (million 2020$, 3 percent discount rate)	
		2022 GHGI factor	**Permian Basin factor[1]**
Costs	Patrols	$151.7	$151.7
	Leakage surveys	$41.5	$41.5
	Leak repairs	$15.1	$14.6
	NMPS reporting	$0.6	$0.6
	Other reporting and recordkeeping	$0.6	$0.6
	Total costs for gathering	**$209.4**	**$208.9**
Benefits	Climate benefits[2]	$491.5	$27,238.9
	Avoided gas losses	$44.7	$2,478.2
	Total benefits for gathering	**$536.2**	**$29,717.1**

[1] Based on emission factor from Chen *et al.* (2022) applied to regulated gathering pipelines in Texas and New Mexico.
[2] Climate benefits based on estimate developed by IWG of the average SC-CH_4 at 3 percent discount.
Source: PHMSA analysis

Note that assuming emission rates based on pipelines in the Permian area for all gathering lines in Texas and New Mexico likely overstates emissions from gathering lines in cases where the pipeline infrastructure in other production areas within the two states are less leak-prone.

6.3 Leak Survey Effectiveness

For the main analysis detailed in this PRIA, PHMSA estimated that baseline practices detect, on average, 85 percent of the leaks that would be detected under the proposed rule. PHMSA understands this value could overstate the effectiveness of existing practices, and therefore understate improvements attributable to the proposed rule. Given the uncertainty surrounding this fundamental input into the calculation of the costs and benefits of the proposed rule, PHMSA conducted a sensitivity analysis using alternate assumptions regarding the effectiveness of leak surveys wherein there is a greater difference between the effectiveness of baseline leak survey practices and practices required under the proposed rule. Specifically, the sensitivity analysis assumes that baseline leak detection practices only achieve 50 percent of what is achievable using "best practices" that would be implemented under the proposed rule.

Section 6.3.1 describes the sources of uncertainty in the estimates of leak detection effectiveness. Section 6.3.2 compares the results of the main analysis, based on a 15-percent difference in leak detection effectiveness, to those of this sensitivity analysis, based on a 50-percent difference in leak detection effectiveness.

6.3.1 Basis of Effectiveness Values

In the main analysis, PHMSA calculated leak incidence rates for gathering and transmission pipelines based on the number of leaks reported by operators in annual reports submitted to PHMSA. PHMSA then assumed that this incidence rate captures only 85 percent of the existing gas leaks that would detected by surveys using ALD equipment and practices. For distribution mains, PHMSA derived leak incidence rates based on empirical studies that used "best practices" to estimate the number of existing gas leaks (Lamb et al., 2015; Weller et al., 2020). PHMSA assumed that the ALDP requirements of the proposed rule would achieve similar performance as the empirical studies and that baseline practices are only 85 percent as effective as the study "best practices."

In general, PHMSA expects that the proposed rule will result in more leaks being detected because of (1) enhanced leak survey and patrol frequency requirements for certain types of pipelines, (2) new ALDP requirements that specify minimum performance standards for leak surveys, and (3) the proposed removal of a broad exception for reporting of any leaks that are corrected by tightening, lubrication, or adjustment in annual reports.

PHMSA cannot precisely estimate the effectiveness of baseline leak detection practices relative to those under the proposed rule. This is because there is no authoritative source of comprehensive data on leak incidence across the different types of PHMSA-regulated pipelines, an unknown proportion of operators may already implement one or more elements of PHMSA's proposed ALDPs, and an unknown proportion of operators may already conduct surveys more frequently than required by federal and/or state regulations.

The assumptions used in the main analysis may overstate the effectiveness of existing practices, and therefore understate the incremental leaks detected under the proposed rule for several reasons:

- PHMSA developed its estimate that conventional survey methods are only 85 percent as effective as ALDP based in part on studies conducted on distribution pipelines demonstrating the success of ALDP methods (*e.g.*, Lamb et al., 2015; Weller et al., 2020) in identifying a greater number of leaks on distribution mains, and in part because it is a long-held value.[86] For distribution pipelines, PHMSA assumed that ALDP methods and procedures implemented under the proposed rule will increase the effectiveness of leak patrols and surveys to be at par with leak indications in Lamb *et al.* (2015) and Weller *et al.* (2020). However, the proposed rule would also increase minimum leak survey frequencies for certain distribution, gathering, and transmission pipelines. Patrols provide another opportunity for identification of leaks that could increase the total leaks discovered under the proposed rule, increasing the difference between leaks discovered under the baseline and the proposed rule. It is uncertain how the change in leak detection practices and survey frequencies combine to change the rate at which existing leaks are detected. The uncertainty is particularly salient for Type C gathering lines since most of these lines are not currently subject to any leakage survey requirements.
- PHMSA derived baseline per-mile leak incidence rates for gathering and transmission pipeline segments based on information submitted by operators in annual reports and applied those uniform incidence rates across all line types in each segment when estimating the total number of leaks detected. However, the leak incidence rate is likely to understate actual leaks for several reasons:
    - The absence of minimum technology performance standards reduces confidence that the number of reported leaks reflects the actual number of leaks occurring across the different pipeline types.
    - PHMSA annual report requirements contemplate that a potentially large number of leaks of all types need not be reported at all if they can be adjusted by tightening, lubrication, or maintenance, thereby reducing the number of detected leaks documented in annual reports.
    - Operators of neither Type B nor Type C gathering lines are subject to patrol or survey requirements, thereby reducing the number of detected leaks that are then reported to PHMSA.

86 See, for example, page A-18 of appendix A from EPA (1995) *Methane Emissions from the Natural Gas Industry*, Volume 3: General Methodology. Accessed online at https://www.epa.gov/sites/default/files/2016-08/documents/3_generalmeth.pdf

- Operators of most Type C gathering lines are not subject to any leakage survey requirements, and PHMSA has not yet received annual reporting data from any Type C gathering operators.[87]
- The proposed ALDP requirements and survey frequencies are minimum standards. Operators may choose to adopt policies or technologies—or states may impose even more rigorous requirements—that result in detection of even more leaks than the baseline, which operators would then be required to repair in accordance with the proposed requirements.

6.3.2 Costs and Benefits by Pipeline Type and Rule Component

Table 55 compares the costs and benefits of the two analyses across pipeline types and analysis components. Assuming a larger improvement in the effectiveness of leak surveys for the proposed rule relative to the baseline increases the number of detected leaks attributable to the proposed rule, and therefore also the number of leaks repaired. These two changes increase the costs attributable to the proposed rule. With respect to benefits, the greater number of leak repairs attributable to the rule results in higher associated reductions in methane emissions and gas losses. While the differences between the two scenarios depend on the industry segment,[88] the overall costs of the sensitivity scenario are 15 to 26 percent larger than the main analysis, whereas the benefits are 58 to 69 percent larger.

Table 55: Summary of incremental costs and benefits of the proposed rule using alternative assumptions regarding the effectiveness of leak surveys.

Category	Million 2020$, annualized at 3 percent discount					
			Distribution		Total[1]	
	Gathering	Transmission	Lamb *et al.* (2015)	Weller *et al.* (2020)	Low[2]	High[2]
Main analysis						
Survey	$193.2	$12.2	$292	$292	$497.6	$497.6
Repair & monitoring	$15.1	$1.5	$220	$359	$236.2	$376.0
Reporting	$1.2	$1.2	$2	$2	$4.8	$4.8
Total costs[2]	**$209.4**	**$14.9**	**$514.2**	**$654.0**	**$738.6**	**$878.4**
Climate benefits[3]	$507.3	$11.1	$471.7	$1,607.2	$990.2	$2,125.6
Gas losses	$46.2	$1.0	$43.2	$147.1	$90.4	$194.3
Total benefits	**$553.5**	**$12.1**	**$514.9**	**$1,754.2**	**$1,080.5**	**$2,319.9**
Net benefits	**$344.1**	**-$2.8**	**$0.7**	**$1,100.2**	**$342.0**	**$1,441.5**
Sensitivity analysis						
Survey	$193.2	$12.2	$292	$292	$497.6	$497.6
Repair & monitoring	$29.8	$8.6	$306	$565	$344.3	$603.2
Reporting	$1.4	$1.3	$3	$3	$5.8	$5.8
Total costs[2]	**$224.4**	**$22.1**	**$601.2**	**$860.1**	**$847.7**	**$1,106.6**

[87] Without access to this information, PHMSA applied the leak incidence figures derived from reports by operators of Type B and Type A gathering pipelines to Type C pipeline mileage. However, potential differences in environmental and operational characteristics and the historical lack of any meaningful safety/integrity requirements could lead to Type C gathering lines having higher leak incidence than Type B and/or Type A gathering pipelines.

[88] The differences in cost and benefits between the main analysis and sensitivity analysis are not linear because changes in leak detection effectiveness does not affect all pipelines in the same way. Differences in survey frequencies for different types of pipelines are also factors and some costs do not depend on leak detection effectiveness.

Table 55: Summary of incremental costs and benefits of the proposed rule using alternative assumptions regarding the effectiveness of leak surveys.						
Category	Million 2020$, annualized at 3 percent discount					
	Gathering	Transmission	Distribution		Total[1]	
			Lamb *et al.* (2015)	Weller *et al.* (2020)	Low[2]	High[2]
Climate benefits[3]	$1,000.7	$62.5	$613.2	$2,305.2	$1,676.4	$3,368.4
Gas losses	$91.0	$5.7	$56.0	$210.2	$152.7	$306.9
Total benefits	**$1,091.8**	**$68.2**	**$669.2**	**$2,515.4**	**$1,829.1**	**$3,675.4**
Net benefits	**$867.3**	**$46.1**	**$68.0**	**$1,655.3**	**$981.4**	**$2,568.7**

[1] Total may not add up due to independent rounding.
[2] 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).
[3] Climate benefits based on estimate developed by IWG of the average SC-CH_4 at 3 percent discount.
Source: PHMSA analysis.

6.4 Leaks from Gas Distribution Services

The analysis of costs and benefits attributable to the proposed leak detection and repair requirements for distribution systems uses distribution main mileage as the basis for estimating the costs and benefits attributable to the rule. PHMSA recognizes that a significant number of leaks occur on service lines and the rule may also help detect and mitigate these leaks. However, there is significant uncertainty on the extent to which there may be additional costs and benefits for these leaks, beyond the estimates presented in the analysis. The sources of uncertainty, discussed further below, include: (1) the number of service leaks that are above and beyond those captured in the incidence and emissions rates used in the analysis, and (2) the additional number of detected and repaired service leaks attributable to the proposed rule.

Regarding the first source of uncertainty, while services were not explicitly broken out in the analysis, they are included to the extent that they are represented in the leak incidence and emissions rates used to model distribution-related costs and benefits. For example, PHMSA used values from Weller *et al.* (2020) as the basis for the upper bound estimate of the number of leaks that may be detected by implementing advanced leak detection (ALD) methods. The analysis further assumed that the detection methods used by Weller *et al.* (2020) are similar to those local distribution companies (LDCs) will be implementing to comply with the proposed requirements (*i.e.*, the types of leaks detected by LDCs would be similar to those represented in Weller *et al.* (2020)).

The Weller-based estimates mostly reflect leaks from distribution mains but may also capture some leaks on services. As Weller *et al.* (2020) note, "*We assume that the leak indications and emissions observed in these surveys are derived from leaks in the gas mains from local distribution systems (e.g., joints, the main tube body, and the T-connection to service lines). Although some of these leaks may arise from service lines or meter set assemblies, leaks from these components are typically smaller and far from the survey vehicle and therefore less likely to be detected. In our previous field work, we found that, for leak indications arising from natural gas sources, the vast majority (93%) was attributable to pipeline leaks*. Weller *et al.* (2020) also note "*We recognize that some utility companies will classify leaks emanating from the service-T as attributable to service lines and not mains. The 2017 EPA emissions estimate from mains and services is 0.22 Tg/year, and our estimate is approximately 3× greater than this* *value*.” The emission estimates developed by Weller *et al.* (2020) are also significantly greater than corresponding estimate from other studies, such as Lamb *et al.* (2015), that purport to capture leaks on both distribution mains AND services.

Even Lamb *et al.* (2015), who report separate leak emission rates for mains and services, note that it is not always possible to distinguish between leaks coming from distribution mains vs. services and therefore the leak incidence and emissions rates for mains may reflect some leaks originating on service lines. Service mileage does not get reported to PHMSA but must be estimated based on main mileage and the number of services, both of which are reported to PHMSA. Both number of services and estimated service mileage are highly correlated with reported main mileage, so calibrating parameters to main mileage should not introduce any significant bias.

Regarding the second source of uncertainty, PHMSA expects that in cases where the service leak is occurring near an occupied building (vs. at the junction with a main), the leak may be more readily detected and reported by residents to the LDC prior to the next scheduled survey. Such leaks would presumably be investigated, are more likely to be identified as grade 1 leaks due to proximity to occupied structures and to be repaired in the baseline.

Estimating service leaks separately (*e.g.*, based on PHMSA or EPA GHGI data) and simply adding them to the estimates included in the analysis may result in double-counting if no adjustments are made. PHMSA lacks data to make the appropriate adjustments.

6.5 Regulatory Alternatives

As described in section 2.1.4, PHMSA considered two primary regulatory alternatives to the proposed rule requirements for distribution systems. These alternatives would set different maximum intervals between leak surveys of distribution systems. One alternative (Alternative 2) would retain the 5-year maximum interval between leak surveys for plastic pipes outside of business districts, whereas the other (Alternative 3) would require annual surveys for all distribution mains.

PHMSA also considered requiring measures to monitor and reduce fugitive methane emissions from gas transmission compression stations and gas G&B compressor stations (Alternative 4) instead of the proposed exemption of gas transmission and gas gathering compressor stations subject to EPA methane emissions standards at 40 CFR part 60 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), advanced leak detection program (ALDP) (§192.763) and qualification of leak detection personnel (§ 192.769).

6.5.1 Alternatives for Distribution Pipelines

Changing the distribution pipeline requirements would result in different mileage of pipeline surveyed each year and corresponding changes in the number and timing of leaks detected, repaired, and monitored, as well as the changes in methane emissions and lost natural gas. Table 56 summarizes the annualized costs and benefits of these alternatives. The table includes corresponding results for the proposed rule for comparison. Note that the costs and benefits shown in Table 56 are for distribution systems only and do not include the costs and benefits associated with requirements for gathering and transmission systems.

Keeping the leak survey interval for plastic mains at 5 years (Alternative 2) reduces annualized costs by approximately $174 million to $260 million dollars, depending on the assumed emission factors and discount rate, but also yields annualized benefits that are $10 million to $456 million smaller.

Requiring annual leak surveys of all distribution mains (Alternative 3) increases annualized compliance costs by $1.3 billion to $1.8 billion—depending on the assumed emission factors and discount rate—while potentially resulting in comparatively smaller benefit gains. Thus, the costs are approximately 3 times larger under Alternative 3 than under the proposed rule, whereas the avoided emissions are only 15 percent to 75 percent larger.[89] Only when annualized benefits are discounted at 3 percent do they increase by a greater margin than the annualized costs. The net effects of this alternative range from significant net costs when using emission factors from Lamb *et al.* (2015) to net benefits when using factors from Weller *et al.* (2020).

Table 56: Annualized costs and benefits of alternative distribution leak survey requirements (million 2020$)

Discount rate and analyzed LDAR requirements		Costs		Benefits		Net Benefits[1]	
		Low[2]	High[2]	Low[2]	High[2]	Low[2]	High[2]
3%	**Proposed rule**	**$740**	**$880**	**$1,081**	**$2,320**	**$341**	**$1,440**
	Alternative 2 – 5-year interval for plastic mains	$565	$625	$1,071	$1,864	$506	$1,239
	Alternative 3 – Annual leak surveys	$2,057	$2,635	$1,251	$4,779	-$806	$2,144
3% and 7%[3]	**Proposed rule**	**$753**	**$900**	**$1,073**	**$2,304**	**$320**	**$1,404**
	Alternative 2 – 5-year interval for plastic mains	$579	$640	$1,063	$1,850	$484	$1,210
	Alternative 3 – Annual leak surveys	$2,066	$2,681	$1,243	$4,749	-$823	$2,068

[1] Negative values represent net costs whereas positive values represent net benefits.
[2] Reflect range of distribution costs and benefits based on assumptions regarding leak incidence and methane emissions rate across pipe materials. The low estimate is based on leak incidence and methane emission rates from Lamb *et al.* (2015), whereas the high estimate is based on rates from Weller *et al.* (2020).
[3] Costs and benefits from avoided natural gas losses (included in total benefits) are discounted at 7 percent, whereas climate benefits (also included in the total benefits) are discounted at 3 percent and based on the average SC-CH_4 at 3 percent discount. See section 5 for estimated climate benefits using other discount rates.
Source: PHMSA analysis

6.5.2 Alternatives for Gas Transmission and Gas Gathering Compressor Stations

Given EPA current and proposed EPA methane emissions requirements at 40 CFR part 60, PHMSA is proposing to exempt gas transmission and gas gathering compressor stations subject

89 Modeled methane emission reductions under the proposed rule are 0.2 to 0.7 MMTon CH_4 per year, on average, during the analysis period (or 62 percent and 44 percent of the corresponding modeled baseline emissions from distribution pipelines), as compared to reductions of 0.2 and 1.2 MMTon CH_4 per year under Alternative 3.

to those EPA requirements from each of the NPRM's proposed requirements pertaining to leak repair (§192.703(c)), leakage survey and patrol (§§ 192.705 and 192.706), leak grading and repair (§192.760), advanced leak detection program (ALDP) (§192.763) and qualification of leak detection personnel (§ 192.769). In proposing these exemptions, PHMSA considered that EPA's regime at 40 CFR part 60 for monitoring fugitive methane emissions from gas transmission compression stations and gas G&B compressor stations provides public safety and environmental protection comparable to PHMSA's proposal.

As of the date of this analysis, only EPA's standards at 40 CFR part 60, subpart OOOOa are effective; other EPA requirements (specifically, 40 CFR part 60, subparts OOOOb and OOOOc) have only been proposed. In the event EPA has not yet finalized the proposed requirements at OOOOb and OOOOc (or those proposed requirements are not in effect for any other reason), PHMSA's proposed exemption would either be limited in scope (i.e., to those gas transmission and G&B compressor stations subject to currently-effective 40 CFR part 60, subpart OOOOa) or eliminated entirely from PHMSA's rulemaking. This section provides the costs and benefits (summarized in Table 57) expected to result from the latter scenario.[90] The analysis is based on the cost and benefits estimated by EPA (U.S. EPA, 2021b, 2021d; see Chapter 12, Compressor Station Costs and Emissions).[91]

Table 57: Summary of costs and benefits of monitoring and repair requirements for G&B and transmission compressor stations

Item	Million 2020$, annualized at 3 percent discount		
	G&B	Transmission	Total
Annualized costs	$47.2	$11.9	$59.2
Annualized benefits	$84.3	$34.8	$119.0
Net benefits	$37.1	$22.8	$59.9

The regulations EPA proposed on November 2021 (86 FR 63110) would require:

- Quarterly emissions monitoring surveys of leaks from all gas transmission compression and gas gathering boosting systems — this is more frequent than PHMSA's proposed leakage survey revisions for all but those facilities in Class 4 locations.

90 PHMSA examines in this analysis the scenario in which its proposed exemption is removed entirely because it understands that scenario to provide an upper bound for both compliance costs and (environmental and public safety) benefits because (absent any exception) all new and existing gas transmission and G&B compressor stations would be subject to PHMSA's proposed leak detection, repair, and performance standards. Alternatively, were PHMSA to retain the exception as proposed, and EPA has not yet finalized its proposed methane emissions standards at subparts OOOOb and OOOOc (or EPA's proposals are not in effect for any other reason), then a subset of gas transmission and G&B compression stations (those that are new, reconstructed, or modified after September 18, 2015) would remain eligible for the proposed exemption, resulting in lower compliance costs and benefits than the no-exemption scenario.

91 While this analysis focuses on quarterly leak monitoring requirements and repair for G&B and transmission sources, EPA also analyzed the costs and benefits of proposed requirements for compressors at gas *storage* facilities, and for different monitoring frequencies (*e.g.*, annual, semiannual, and monthly).

- Surveys performed using leak detection equipment; either optical gas imaging (such as FID) or another "instrument" with sensitivity of at least 500 PPM that complies with method DA in appendix A-7 to 40 CFR part 60 — these standards are similar to the leak detection equipment contemplated by PHMSA's NPRM.
- Operator first attempt at repair of any detected fugitive emissions within 30 days and complete repairs within 30 days of first attempt — this is a more aggressive timeline than contemplated by this NPRM for most (*i.e.*, grades 2 and 3) leaks.[92]

EPA estimated the costs associated with three main categories of compliance activities: (1) the periodic monitoring for leaks, (2) the repair of leaks identified, and (3) the documentation of the activities, as well as costs associated with planning and preparation (*e.g.*, development of the monitoring plan and of a system to record monitoring and repair information). Table 58 summarizes total annual costs per source.

Table 58: Annual compliance costs for quarterly monitoring requirements, by source.			
Annual compliance costs basis for quarterly monitoring	Dollar Year[2]	Source	
		G&B	Transmission
Total annual cost per source with amortized capital cost (without gas savings)[1]	2019$	$13,379	$19,929
	2020$	$13,542	$20,171
Source in U.S. EPA (2021b)		Table 12-8b	Table 12-8c
Total annual cost per source with amortized capital cost (with gas savings)	2019$	$10,966	$19,929
	2020$	$11,099	$20,171
Source in U.S. EPA (2021b)		Table 12-14a	Table 12-14a
[1] Annual cost includes quarterly monitoring cost and amortization of capital cost over 8 years at 7% interest. [2] EPA estimated costs in 2019 dollars. PHMSA updated the costs to 2020 dollars using the GDP deflator (1.012)			

EPA projected the number of G&B and transmission compressor sources using GHGI data.[93] As of 2021, EPA estimated a total of 1,484 G&B and 252 transmission sources. EPA projected annual increases of 212 G&B and 36 transmission sources.

Table 59 summarizes the total compliance costs each year, obtained by multiplying the number of sources each year, by the annual compliance costs. Total compliance costs are lower when one nets out savings from avoided gas losses (*e.g.*, for the G&B segment net costs are $38.7 million vs. $47.2 million in Table 59, annualized at 3 percent discount).

Table 59: Total compliance costs for quarterly monitoring requirements applicable to G&B and transmission compressor sources						
Year	Number of sources			Costs (million, 2020$)		
	G&B	Transmission	Total	G&B	Transmission	Total
2024	2,120	360	2,480	$28.7	$7.3	$36.0
2025	2,332	396	2,728	$31.6	$8.0	$39.6
2026	2,544	432	2,976	$34.4	$8.7	$43.2

92 Although EPA's repair timelines may be less demanding than those PHMSA is proposing 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.

93 Station counts are extracted from the following rows: *Yard Piping* (gathering and boosting) and *Station + Compressor Fugitive Emissions* (transmission and storage)

Table 59: Total compliance costs for quarterly monitoring requirements applicable to G&B and transmission compressor sources							
Year		Number of sources			Costs (million, 2020$)		
		G&B	Transmission	Total	G&B	Transmission	Total
2027		2,756	468	3,224	$37.3	$9.4	$46.8
2028		2,968	504	3,472	$40.2	$10.2	$50.4
2029		3,180	540	3,720	$43.1	$10.9	$54.0
2030		3,392	576	3,968	$45.9	$11.6	$57.6
2031		3,604	612	4,216	$48.8	$12.3	$61.1
2032		3,816	648	4,464	$51.7	$13.1	$64.7
2033		4,028	684	4,712	$54.5	$13.8	$68.3
2034		4,240	720	4,960	$57.4	$14.5	$71.9
2035		4,452	756	5,208	$60.3	$15.2	$75.5
2036		4,664	792	5,456	$63.2	$16.0	$79.1
2037		4,876	828	5,704	$66.0	$16.7	$82.7
2038		5,088	864	5,952	$68.9	$17.4	$86.3
3%	**Total PV**				**$580.7**	**$146.9**	**$727.6**
	Annualized				**$47.2**	**$11.9**	**$59.2**
7%	**Total PV**				**$440.9**	**$111.5**	**$552.4**
	Annualized				**$45.2**	**$11.4**	**$56.7**

EPA estimated the avoided methane emissions from leak detection and subsequent repairs. Table 60 summarizes avoided methane emissions per source.

Table 60: Annual avoided emissions costs for quarterly monitoring requirements, by source		
Avoided emissions per source	Source	
	G&B	Transmission
CH_4 (tons/year)	13.31	32.31
VOC (tons/year)	3.70	0.89
Source in U.S. EPA (2021b)	Table 12-14a	Table 12-14a

Table 61 summarizes the total avoided methane emissions each year, obtained by multiplying the number of sources each year by the annual avoided emissions per source. The table also provides the value of methane-related benefits, based on the average value of the SC-CH_4 at a 3 percent discount rate (Interagency Working Group on Social Cost of Greenhouse Gases, 2021).

Table 61: Avoided methane emissions and benefits for quarterly monitoring of G&B and transmission compressor sources								
Year		Methane emission reductions (tons/year)			$SC-CH_4$ (3% average, 2020$/ metric ton)	Avoided climate benefits (million 2020$, 3% average)		
		G&B	Transmission	Total		G&B	Transmission	Total
2024		28,208	11,633	39,841	$1,600	$40.9	$16.9	$57.8
2025		31,029	12,796	43,825	$1,700	$47.9	$19.7	$67.6
2026		33,850	13,959	47,809	$1,700	$52.2	$21.5	$73.7
2027		36,670	15,122	51,793	$1,800	$59.9	$24.7	$84.6
2028		39,491	16,286	55,777	$1,800	$64.5	$26.6	$91.1
2029		42,312	17,449	59,761	$1,900	$72.9	$30.1	$103.0
2030		45,133	18,612	63,745	$1,900	$77.8	$32.1	$109.9
2031		47,953	19,776	67,729	$2,000	$87.0	$35.9	$122.9
2032		50,774	20,939	71,713	$2,000	$92.1	$38.0	$130.1
2033		53,595	22,102	75,697	$2,100	$102.1	$42.1	$144.2
2034		56,416	23,265	79,681	$2,100	$107.5	$44.3	$151.8
2035		59,237	24,429	83,665	$2,200	$118.2	$48.8	$167.0
2036		62,057	25,592	87,649	$2,200	$123.9	$51.1	$174.9
2037		64,878	26,755	91,633	$2,300	$135.4	$55.8	$191.2
2038		67,699	27,918	95,617	$2,300	$141.3	$58.3	$199.5
3%	**Total PV**					**$1,036.3**	**$427.4**	**$1,463.7**
	Annualized					**$84.3**	**$34.8**	**$119.0**

7 Initial Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA) of 1980, as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996, requires federal agencies to consider the impact of their rules on small entities, to analyze alternatives that minimize those impacts,[94] and to make their analyses available for public comments. The RFA is concerned with three types of small entities: small businesses, small nonprofits, and small government jurisdictions.

The RFA describes the regulatory flexibility analyses and procedures that must be completed by federal agencies unless they certify that the rule, if promulgated, would not have a significant economic impact on a substantial number of small entities. This certification must be supported by a statement of factual basis, *e.g.*, addressing the number of small entities affected by the proposed action, estimated cost impacts on these entities, and evaluation of the economic impacts.

This section provides the Initial Regulatory Flexibility Analysis (IRFA) of the proposed rule. Following the standard IRFA outline, the following subsections provide:

- A description of the reasons the agency is considering the action;
- A succinct statement of the objectives and legal basis of the rule;
- A description and estimate of the number of small entities to which the rule will apply (or an explanation of why no such estimate is available);
- A description of the compliance requirements of the rule and their costs;
- A description of relevant Federal rules, if any, that may duplicate, overlap, or conflict with the proposed rule; and
- A description of any significant alternatives to the proposed rule that would accomplish the stated objectives of the rule while minimizing any significant economic impact of the proposed rule on small entities.

Several of the recommended IRFA elements specified in SBA guidelines (SBA, 2017)[95] are covered in detail in the NPRM or in other sections of this report and summarized as background

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94 Section 603(c) of the RFA provides examples of such alternatives as: (1) the establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities; (2) the clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities; (3) the use of performance rather than design standards; and (4) an exemption from coverage of the rule, or any part thereof, for such small entities.

95 Under section 603(b) of the RFA, an IRFA must describe the impact of the proposed rule on small entities and contain the following information:
1. A description of the reasons why the action by the agency is being considered.
2. A succinct statement of the objectives of, and legal basis for, the proposed rule.
3. A description—and, where feasible, an estimate of the number—of small entities to which the proposed rule will apply.

in section 7.1. The remainder of this section focuses on estimating the number of small entities to which the proposed rule will apply (section 7.2), providing an assessment of the economic impacts on these entities (sections 7.3 and 7.4), and reviewing uncertainties and limitations in the analysis (section 7.5).

7.1 Background

7.1.1 Reasons for the Action

The NPRM and section 1 of this report detail the reasons why the Agency is considering this action. Briefly, this action is being taken to reduce release of methane, a potent greenhouse gas that contributes to climate change, from natural gas pipeline infrastructure. In addition, the proposed rule is responsive to a bipartisan Congressional mandate from the PIPES Act of 2020.

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, or reflect the scientific consensus that prompt reductions in methane emissions from natural gas infrastructure are critical to limiting the impacts of climate change.

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.

In the accompanying NPRM, 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.

7.1.2 Objectives and Legal Basis for the Rule

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

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4. A description of the projected reporting, recordkeeping, and other compliance requirements of the proposed rule, including an estimate of the classes of small entities that will be subject to the requirement and the types of professional skills necessary for preparation of the report or record.
5. An identification, to the extent practicable, of all relevant federal rules that may duplicate, overlap, or conflict with the proposed rule.

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)).

PHMSA proposes a series of regulatory amendments to the Federal pipeline safety regulations (49 CFR parts 190-199) in response to a bipartisan congressional mandate in the PIPES Act of 2020 (Pub. L. 116-260) and a policy commitment of the Biden-Harris Administration to reduce methane emissions by 30 percent below 2020 levels before 2030. 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 UNGSFs and 165 LNG facilities, thereby improving public safety, promoting environmental justice, and addressing the climate crisis.

Specifically, the 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. 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 the NPRM) required for regulation of those pipeline facilities under the Federal Pipeline Safety Statutes. And 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.

7.1.3 Relevant Federal Rules

The NPRM covers the relationship between the proposed rule and other relevant Federal and State regulations. Additional details on federal regulations are summarized in section 7.6.

7.1.4 Compliance Requirements and their Costs

Section 4 of this report describes the compliance requirements of the proposed rule and their costs.

7.1.5 Alternatives to the Proposed Rule to Minimize Significant Economic Impact on Small Entities

PHMSA developed the proposed rule to minimize and mitigate potential impact on small entities by setting performance standards for advanced leak detection but providing flexibility to operator to select the equipment and methods best adapted to their particular circumstances. PHMSA did not identify significant alternatives to the proposed rule that would accomplish the methane emission reduction objectives in the PIPES Act of 2020 while minimizing the economic impact of the proposed rule on small entities.

7.2 Description and Estimate of Affected Small Entities

PHMSA identified the size of each parent entity using the SBA size threshold guidelines in effect as of July 14, 2022 (SBA, 2019). The criteria for entity size determination vary by the organization/operation category of the parent entity, as follows:

- **Publicly owned (government) entities**: Publicly owned entities include federal, State, municipal, and other political subdivision entities. Entities with populations less than 50,000 are considered to be small.
- **Privately owned (non-government) entities**: Privately owned entities (inclusive of investor-owned entities) include companies with natural gas extraction, pipeline transportation, natural gas distribution, or other primary businesses. Small entities are those with less than the threshold number of employees or revenue specified by SBA for each relevant North American Industry Classification System (NAICS) sector. For example, for natural gas distribution, the size standard is based on the number of employees, with small entities being those with fewer than 1,000 employees. For firms in the pipeline transportation of natural gas sector, the size standard is based on revenue, with small entities being those with less than $30 million in annual revenue. Table 62 lists the NAICS sectors most frequency associated with operators subject to the proposed rule, based on the primary NAICS identified by matching each operating company to Dun & Bradstreet (D&B) data (Dun & Bradstreet, 2021).

Table 62: NAICS codes and SBA size standards for non-government entities

NAICS code[1]	NAICS description	SBA size standard
211120	Crude petroleum extraction	1,250 employees
211130	Natural gas extraction	1,250 employees
213111	Drilling Oil and Gas Wells	1,000 employees
213112	Support activities for oil and gas operations	$41.5 million
221122	Electric power distribution	1,000 employees
221118	Other electric power generation	250 employees
221210	Natural gas distribution	1,000 employees
221310	Water supply and irrigation systems	$30.0 million
324110	Petroleum Refineries	1,500 employees
447190	Other Gasoline Stations	$16.5 million
486210	Pipeline transportation of natural gas	$30.0 million
486990	All Other Pipeline Transportation	$40.5 million

[1] NAICS codes reflect data from D&B for each operator. Certain pipeline systems affected by this rulemaking are owned by non-government entities whose primary business is neither natural gas extraction nor transportation or distribution.
[2] Based on size standards effective at the time PHMSA conducted this analysis (SBA, 2019).
Source: Dun & Bradstreet, 2021; SBA, 2019

To determine whether a parent owner is a small entity according to these criteria, PHMSA compared the relevant entity size criterion value estimated for each parent entity to the SBA threshold value. This analysis is done at the level of the highest domestic parent owner for which PHMSA have information. PHMSA used the following data sources and methodology to estimate the relevant size criterion values for each parent entity:

- **Population**: Population data for municipalities and other non-state political subdivisions were obtained from the U.S. Census Bureau (2020). For municipal utilities, PHMSA assumed that the location of the reported headquarters address indicates the relevant geographical place for obtaining population data.
- **Employment**: PHMSA used parent-level employment values from D&B if available, or from corporate websites if D&B data were not available.
- **Revenue**: PHMSA used 2019 revenue reported in form EIA-176 "Annual Report of Natural and Supplemental Gas Supply and Disposition" (EIA, 2020) if the values were available. For entities that did not report to EIA, PHMSA compiled information from corporate websites (*e.g.*, annual financial reports and filings to the U.S. Securities and Exchange Commission (SEC)), D&B or Internet searches, or estimated entity-level revenue values based on the number of services in the 2020 Annual Gas Distribution Report, and average residential gas consumption and average natural gas prices from EIA (Energy Information Administration, 2021). PHMSA was unable to find revenue data for 4 entities that own distribution systems and for 132 entities that own gathering and transmission systems. For the purpose of this analysis, these entities are generally assumed to be small.

Table 63 presents the total number of part 192-regulated gas pipeline systems by type and size of the parent owning entity. There are notable differences between the major industry segments: whereas gas gathering and transmission systems are mostly privately-owned (87 percent), gas distribution systems are more likely to be owned by municipal and other government entities (69 percent). In both major segments, a vast majority of systems are owned by small entities – 63 percent for gas gathering and transmission and 87 percent for gas distribution.

Table 63: Gas pipeline systems by industry segment and type and size of owning entity

Segment	Entity type	Number of operators by size of parent owner			Entity type as % of total
		Small	Large	Total	
Gathering and Transmission	Government	145	19	164	13%
	Privately-owned	680	464	1,144	87%
	Total	825	483	1,308	100%
	Size as % of total	63%	37%	100%	
Distribution	Government	871	42	913	69%
	Privately-owned	279	130	409	31%
	Total	1,150	172	1,322	100%
	Size as % of total	87%	13%	100%	
Total[1]	Government	959	49	1,008	42%
	Privately-owned	913	484	1,397	58%
	Total	1,872	533	2,405	100%
	Size as % of total	78%	22%	100%	

[1] The table defines as a "system" a unique combination of operator and state. The total does not add up due to some entities operating gathering and transmission and distribution pipelines in the same states.
Source: PHMSA analysis

7.3 Small Firms Cost-to-Revenue Test

Two criteria are generally assessed in determining whether the regulatory options would have "a significant impact on a substantial number of small entities" (SISNOSE):

- Is the *absolute number* of small entities estimated to incur a potentially significant impact, as described above, *substantial*?
- Do these *significant impact* entities represent a *substantial* fraction of small entities in the electric power industry that could potentially be within the scope of a regulation?

A measure of the potential impact of the regulatory options on small entities is the fraction of small entities that have the potential to incur a significant impact. For example, if a high percentage of potentially small entities incur significant impacts even though the absolute number of significant impact entities is low, then the rule could represent a substantial burden on small entities.

One way to assess the extent of economic/financial impact on small entities is to compare estimated direct compliance costs to estimated entity revenue (also referred to as the "sales test"). The analysis is based on the ratio of estimated annualized after-tax compliance costs to annual revenue of the entity.

PHMSA used threshold compliance costs of one percent or three percent of entity-level revenue to categorize the degree of *significance* of the economic impacts on small entities. PHMSA determined whether the number of small entities impacted is *substantial* based on (1) the estimated *absolute numbers* of small entities incurring potentially significant impacts according to the two cost impact criteria, and (2) the *percentage of small entities* in the relevant entity categories that are estimated to incur these impacts.

7.3.1 Gas Gathering and Gas Transmission

A total of 782 small entities own 827 gas gathering and transmission systems subject to the proposed rule (out of a total of 1,308 systems that reported to PHMSA in 2020).[96] For this analysis, PHMSA first totaled the costs of all systems owned by each parent entity for each year of the period of analysis for patrols, leak surveys, repairs, and other reporting and recordkeeping.[97] PHMSA then annualized and discounted these costs at 7 percent and adjusted them to reflect the tax treatment of different types of entities depending on the state where the entity operates. After-tax costs are a more meaningful measure of compliance impact on privately owned entities as they incorporate approximate capital depreciation and other relevant tax treatments of compliance expenses. PHMSA calculated the after-tax value of compliance costs by applying combined federal and State tax rates to the pre-tax cost values for privately

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96 Some parent entities own several gas gathering and transmission system operators.

97 For reporting and recordkeeping, PHMSA used the average annualized costs per operator of $4,909 for gathering pipeline operators subject to NPRM requirements and $1,496 for operators subject to all other reporting requirements(using a 7-percent discount rate). See section 4.1.4 for details.

owned entities.[98] For this adjustment, PHMSA used State corporate rates from the Federation of Tax Administrators (2021) combined with a 21 percent federal corporate tax rate.

Table 64: Tax adjustment to compliance costs incurred by privately owned entities, by state

State	State tax rate	Federal tax rate	Total tax rate[1]
Alabama	6.5%	21.0%	26.1%
Alaska	9.4%	21.0%	28.4%
Arizona	4.9%	21.0%	24.9%
Arkansas	6.2%	21.0%	25.9%
California	8.8%	21.0%	28.0%
Colorado	4.6%	21.0%	24.6%
Connecticut	7.5%	21.0%	26.9%
Delaware	8.7%	21.0%	27.9%
District of Columbia	8.3%	21.0%	27.5%
Florida	4.5%	21.0%	24.5%
Georgia	5.8%	21.0%	25.5%
Hawaii	6.4%	21.0%	26.1%
Idaho	6.9%	21.0%	26.5%
Illinois	9.5%	21.0%	28.5%
Indiana	5.3%	21.0%	25.1%
Iowa	9.8%	21.0%	28.7%
Kansas	4.0%	21.0%	24.2%
Kentucky	5.0%	21.0%	25.0%
Louisiana	8.0%	21.0%	27.3%
Maine	3.5%	21.0%	23.8%
Maryland	8.3%	21.0%	27.5%
Massachusetts	8.0%	21.0%	27.3%
Michigan	6.0%	21.0%	25.7%
Minnesota	9.8%	21.0%	28.7%
Mississippi	5.0%	21.0%	25.0%
Missouri	4.0%	21.0%	24.2%
Montana	6.8%	21.0%	26.3%
Nebraska	7.8%	21.0%	27.2%
Nevada	0.0%	21.0%	21.0%
New Hampshire	7.7%	21.0%	27.1%
New Jersey	9.0%	21.0%	28.1%
New Mexico	5.9%	21.0%	25.7%
New York	6.5%	21.0%	26.1%
North Carolina	2.5%	21.0%	23.0%
North Dakota	4.3%	21.0%	24.4%
Ohio	0.0%	21.0%	21.0%
Oklahoma	6.0%	21.0%	25.7%
Oregon	7.6%	21.0%	27.0%
Pennsylvania	10.0%	21.0%	28.9%
Rhode Island	7.0%	21.0%	26.5%
South Carolina	5.0%	21.0%	25.0%
South Dakota	0.0%	21.0%	21.0%
Tennessee	6.5%	21.0%	26.1%
Texas	0.0%	21.0%	21.0%
Utah	5.0%	21.0%	24.9%
Vermont	6.0%	21.0%	25.7%
Virginia	6.0%	21.0%	25.7%
Washington	0.0%	21.0%	21.0%
West Virginia	6.5%	21.0%	26.1%

98 Government-owned entities and cooperatives are not subject to income taxes.

Table 64: Tax adjustment to compliance costs incurred by privately owned entities, by state			
State	State tax rate	Federal tax rate	Total tax rate[1]
Wisconsin	7.9%	21.0%	27.2%
Wyoming	0.0%	21.0%	21.0%
[1] Total tax rate is calculated as [state tax rate + federal tax rate – (state tax rate × federal tax rate)] *Sources: State corporate rates from the Federation of Tax Administrators (2021)*			

7.3.2 Gas Distribution

A total of 1,135 small entities own 1,150 gas distribution operators subject to the proposed rule (this is out of the total of 1,322 unique operators that reported to PHMSA in 2020).[99] For this analysis, PHMSA first totaled the costs of all operators owned by each parent entity for each year of the period of analysis for leak surveys, repairs, monitoring, and other reporting and recordkeeping.[100] Similarly to the approach used for gathering and transmission, PHMSA then annualized and discounted these costs at 7 percent and adjusted them to reflect the tax treatment of different types of entities depending on the state where the entity operates.

7.4 Compliance Cost Impact Estimates

When looking across industry segments, a total of 1,815 small entities owned gas gathering, gas transmission, or gas distribution systems in 2020, with some entities owning both gas gathering or transmission *and* gas distribution systems. To assess the relative impacts of the proposed rule on each entity, PHMSA combined the total annualized after-tax costs at the entity level across industry segments, before dividing these costs by the estimated annual revenue for the entity. Table 65 summarizes the results of this analysis for the 1,815 entities with regulated systems. The results are presented as a range, following from the estimated range of gas distribution costs.

There are no set thresholds for assessing the significance of the impacts. Following common practice, entities incurring costs below one percent of revenue are unlikely to face significant economic impacts, while entities with costs of at least one percent of revenue have a higher chance of facing significant economic impacts, if they had to absorb the costs, and entities incurring costs of at least three percent of revenue have a still higher probability of significant economic impacts, again if they had to absorb the costs. For 51 percent to 65 percent of small entities, the after-tax compliance costs are estimated to be 1 percent or greater of annual revenue; for 22 percent to 35 percent of small entities, the costs are 3 percent or greater than the revenue.

99 Some parent entities own several gas distribution system operators. For example, D&B identifies Chesapeake Utilities Corporation as the parent owner of Chesapeake Utilities and of Elkton Gas who operate gas distribution systems in the state of Delaware.

100 For reporting and recordkeeping, PHMSA used the average annualized costs per operator of $1,989 (using a 7-percent discount rate). See section 4.2.3 for details. For some small operators with very little distribution mileage, these costs represent a significant share of the estimated costs of the proposed rule.

Table 65: Summary of costs-to-revenue ratios for small entities that own gas gathering, transmission or distribution operators, by cost to revenue ratios and basis for estimating leak incidence				
Cost-to-revenue ratio	**Low[1]**		**High[1]**	
	Number of small entities	**% of small entities**	**Number of small entities[1]**	**% of small entities**
No revenue[2]	148	8%	148	8%
>0% to <1%	736	41%	486	27%
≥1% to <3%	536	30%	541	30%
≥3%	395	22%	640	35%
Total	**1,815**	**100%**	**1,815**	**100%**

[1] 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] PHMSA was unable to find revenue data for 156 entities that own pipeline systems, including 148 entities PHMSA categorized as small due to the lack of revenue data. PHMSA will continue to review available data to obtain or estimate revenue for these entities. All of these small entities own gathering and transmission systems, and three own gathering, transmission, and distribution systems.
Source: PHMSA analysis

As discussed in section 3.1.3, there is uncertainty on the number of operators associated with Type C gathering lines since they have not been required to report to PHMSA until recently. For this analysis, PHMSA assumed that the same operators who operate Type A and Type B gathering lines also operate Type C gathering lines and distributed Type C gathering pipelines mileage (and associated compliance costs) to the known operators. This approach overstates impacts of the proposed rule on these operators in the event that Type C gathering pipelines are instead operated by other firms. For example, the average cost per operator is approximately $531,000 when distributed only among the 378 operators known to operate part 192-regulated Type A and Type B gathering, as compared to approximately $102,000 when distributed among 1,969 operators.[101]

7.5 Uncertainty and Limitations

Despite PHMSA's use of the best available information and data, this IRFA provides only a limited understanding of the potential impacts of the proposed rule on small entities. Table 66 highlights the principal sources of uncertainties and limitations present in this screening analysis.

Table 66: Principal sources of uncertainty in the RFA analysis.		
Item	**Sources of uncertainty**	**Direction of the impact**
Uncertainty in the assignment of NAICS sector to a given entity	D&B identifies one or more NAICS sectors for a given entity. For this analysis PHMSA used the first NAICS code associated with the record. SBA size thresholds may differ across NAICS codes.	Direction unknown

101 The higher count of 1,969 includes 1,591 operators that may be associated with Type C gathering lines based on the assumption that 80 percent of the Type C gathering lines mileage is operated by different entities (See section 3.1.3). These operators are in addition to the 378 operators known to operate Type A and Type B gathering lines that are estimated to also operate the remaining 20 percent of Type C gathering line milage.

Table 66: Principal sources of uncertainty in the RFA analysis.		
Item	**Sources of uncertainty**	**Direction of the impact**
Gaps in revenue and employment data	There are significant gaps in the available revenue and employment data used to categorize entities by size. PHMSA was unable to find revenue data for 136 entities that own pipeline systems and generally categorized these entities as small (128 entities). In addition, the available data from EIA and D&B records often relate to the immediate operator instead of the parent company. These gaps can result in an entity being categorized as small when it would be large when considering the parent, and in the estimated cost-to-revenue ratios being larger than actual ratios.	Overstate number of small entities Overstate impacts
Uncertainty in entity revenue data	Revenue data reported in D&B and other databases are uncertain and may provide an inaccurate picture of actual entity revenue. EIA data provides only revenue associated with distribution. While PHMSA also compiled revenue data from annual reports and other public sources for individual entities, the entities for which this information was available tend to be relatively large (*e.g.*, publicly traded companies).	Overstate impacts
Use of average unit costs	As discussed in section 4, PHMSA uses average unit costs to estimate the costs of conducting surveys, repairing leaks, and conducting other activities to comply with the proposed rule requirements. PHMSA applies these costs to individual systems based on the number of miles of mains and pipe material and other characteristics that affect leak incidence, but these estimates remain approximate and more appropriate for use across the industry. In actuality, costs and other factors are expected to vary across systems and small entities may have higher or lower costs than PHMSA estimated.	Direction unknown
Cost pass-through assumption	The analysis implicitly assumes that none of the compliance costs are passed through to consumers when assessing the impacts on entities. In fact, PHMSA expects that natural gas operators may adjust rates as needed to reflect higher costs of service.	Overstate impacts
Operators of Type C gathering lines are the same as those of Type A and Type B gathering lines	There is uncertainty on the number of operators associated with Type C gathering lines since they have not been required to report to PHMSA until recently. PHMSA assumed that the same operators who operate Type A and Type B gathering lines also operate Type C gathering lines and distributed Type C gathering pipelines mileage (and associated compliance costs) to the known operators. This approach overstates impacts of the proposed rule on these operators in the event that Type C gathering pipelines are instead operated by other firms.	Overstate impacts
Uniform reporting and recordkeeping costs	For this analysis, PHMSA assumed that all operators would incur the same average annualized costs for reporting and recordkeeping to which they are subject, based on the estimate in sections 4.1.4, 4.1.5, and 4.2.3 (*e.g.*, $1,996 per gas distribution operator, $1,245 per transmission operator, $2,897 per part 192-regulated gathering operator, plus $1,760 per operator of part 192-regulated gathering operator newly subject to NPMS reporting requirements). Using this average cost for all operators may overstate the reporting and recordkeeping burden of small operators with very low mains mileage.	Overstate impacts

As described above, the assumption that operators would have to absorb all compliance costs is an extreme worst case that is unlikely to occur for this particular sector. To further inform the assessment of the economic implications of the proposed rule on small entities, PHMSA evaluated an alternative analytic scenario wherein regulated gathering and transmission operators are able to pass through only 50 percent of the incremental costs in the form of increased rates, and distribution operators are able to pass through 90 percent of the incremental costs. Table 67 presents the results of this alternative scenario.

The results show a much smaller impact on small entities. For 18 percent to 28 percent of small entities, the after-tax compliance costs are estimated to be 1 percent or greater of annual revenue; for 9 percent to 11 percent of small entities, the costs are 3 percent or greater than the revenue. PHMSA welcomes comments on the ability of operators in different segments and markets to pass through compliance costs.

Table 67: Summary of costs-to-revenue ratios for small entities that own gas gathering, transmission or distribution operators, by cost to revenue ratios and basis for estimating leak incidence for alternative scenario with partial cost passthrough

Cost-to-revenue ratio	Lamb *et al.* (2015)		Weller *et al.* (2020)	
	Number of small entities	% of small entities	Number of small entities[1]	% of small entities
No revenue[1]	148	8%	148	8%
>0% to <1%	1,334	73%	1,164	64%
≥1% to <3%	173	10%	300	17%
≥3%	160	9%	203	11%
Total	**1,815**	**100%**	**1,815**	**100%**

[1] PHMSA was unable to find revenue data for 156 entities that own pipeline systems, including 148 entities PHMSA categorized as small due to the lack of revenue data. All of these small entities own gathering and transmission systems, and three own gathering, transmission, and distribution systems.
Source: PHMSA analysis

7.6 Other Federal Rules

Aside from PHMSA, several other Federal agencies have jurisdiction over gas pipelines and facilities.

- EPA regulates air emissions from new and existing sources in the crude oil and natural gas source category under the Clean Air Act (CAA) section 111. EPA promulgated regulations at 40 CFR part 60 setting standards for greenhouse gases in the form of limitations on methane and VOC emissions from sources of emissions from exploration/production, processing, transmission, and storage segments in the oil and natural gas source category.[102] Among the gas pipeline facilities within the scope of EPA's 40 CFR part 60 regulatory structure are compressor stations on gas transmission pipelines and boosting stations on gas gathering pipelines. EPA's regulations contain requirements for methane emissions monitoring, repair, and maintenance of those facilities and their appurtenances (including pneumatic controllers and pumps, storage vessels, and sweetening units) for these sources.
- The Federal Energy Regulatory Commission (FERC) within the Department of Energy (DOE) reviews applications for construction and operation of interstate natural gas pipelines,

[102] 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, 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."

storage, and LNG facilities under the authority of section 7 of the Natural Gas Act. As part of this review, FERC issues environmental assessments or draft and final environmental impact statement for comment on most projects. FERC considers greenhouse gas emissions in natural gas project reviews and certification of interstate natural gas pipelines. FERC itself has no jurisdiction over pipeline safety or security.

- The Bureau of Land Management (BLM) within the Department of the Interior regulates the extraction of oil and gas from federal lands. BLM manages the Federal government's onshore subsurface mineral estate, about 700 million acres. BLM also oversees oil and gas operations on many Tribal leases and maintains an oil and natural gas leasing program. BLM does not directly regulate emissions for the purposes of air quality but does regulate venting and flaring of natural gas for the purposes of preventing waste. An operator may also be required to control/mitigate emissions as a condition of approval on a drilling permit. These requirements may apply to certain gathering lines regulated by PHMSA.
- The Bureau of Ocean Energy Management (BOEM) within the Department of the Interior manages the development of America's offshore energy and mineral resources. BOEM has certain air quality regulatory authority over activities that BOEM authorizes on the Outer Continental Shelf of the United States in the Gulf of Mexico, west of 87.5 degrees longitude, and adjacent to the North Slope Bureau of the State of Alaska. These requirements may apply to offshore gas pipelines and facilities within the scope of PHMSA regulations.

The NPRM for this action provides additional details on these regulations and how PHMSA coordinated the proposed rule with other federal agencies.

8 Other Applicable Statutes or Executive Orders

The sections below discuss PHMSA's assessment of the proposed rule against requirements set in various other statutes and executive orders. A separate document provides PHMSA's assessment of the environmental effects of this proposed rule, in accordance with the requirements of the National Environmental Policy Act (NEPA) (42 U.S.C. § 4321 *et seq.*) (PHMSA, 2023).

8.1 Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), as amended by Executive Order 14094 (88 FR 21879, April 11, 2023), PHMSA must determine whether the regulatory action is "significant" and therefore subject to review by the Office of Management and Budget (OMB) and other requirements of the Executive Order. As amended, Executive Order 12866defines a "significant regulatory action" as one that is likely to result in a regulation that may:

- Have an annual effect on the economy of $200 million or more (adjusted every 3 years by the Administrator of OMB's Office of Information and Regulatory Affairs (OIRA) for changes in gross domestic product), or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, territorial, or tribal governments or communities; or
- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; or
- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- Raise legal or policy issues for which centralized review would meaningfully further the President's priorities or the principles set forth in the Executive Order, as specifically authorized in a timely manner by the Administrator of OIRA.

Executive Order 13563 (76 FR 3821, January 21, 2011) was issued on January 18, 2011. This Executive Order supplements Executive Order 12866 by outlining the President's regulatory strategy to support continued economic growth and job creation, while protecting the safety, health and rights of all Americans. Executive Order 13563 requires considering costs, reducing burdens on businesses and consumers, expanding opportunities for public involvement, designing flexible approaches, ensuring that sound science forms the basis of decisions, and retrospectively reviewing existing regulations.

Pursuant to the terms of Section 3(f)(1) of Executive Order 12866, as amended, PHMSA determined that the final rule is a "significant regulatory action" because the action is likely to have an annual effect on the economy of $200 million or more. As such, the action is subject to review by OMB under Executive Orders 12866 and 13563. Any changes made in response to OMB suggestions or recommendations will be documented in the docket for this action.

Table 68 summarizes PHMSA's findings of the potential benefits and costs associated with this action. At the 3-percent discount rate, the proposed rule is estimated to have net annualized benefits ranging from $341 million to $1,440 million, whereas at the 7-percent discount the net effects range from net annualized benefits of $320 to $1,404 million.

Table 68: Annualized costs and benefits of the proposed rule (million 2020$)						
Discount rate	Costs		Benefits		Net benefits[1]	
	Low	High	Low	High	Low	High
3%	$740	$880	$1,081	$2,320	**$341**	**$1,440**
7%[2]	$753	$900	$1,073	$2,304	**$320**	**$1,404**

[1] Total may not add up due to independent rounding.
[2] Costs and benefits from avoided natural gas losses are discounted at 7 percent whereas climate benefits, included in the total benefits, are discounted at 3 percent. See section 5 for estimated climate benefits using other discount rates.
Source: PHMSA analysis

8.2 Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 requires Agencies to prepare a Statement of Energy Effects when undertaking certain agency actions. Such Statements of Energy Effects shall describe the effects of certain regulatory actions on energy supply, distribution, or use, notably: (i) any adverse effects on energy supply, distribution, or use (including a shortfall in supply, price increases, and increased use of foreign supplies) should the proposal be implemented, and (ii) reasonable alternatives to the action with adverse energy effects and the estimated effects of such alternatives on energy supply, distribution, and use.

The OMB implementation memorandum for Executive Order 13211 outlines specific criteria for assessing whether a regulation constitutes a “significant energy action” and would have a “significant adverse effect on the supply, distribution or use of energy.” [103] Those criteria include:

- Reductions in crude oil supply in excess of 10,000 barrels per day;
- Reductions in fuel production in excess of 4,000 barrels per day;
- Reductions in coal production in excess of 5 million tons per year;
- Reductions in natural gas production in excess of 25 million mcf per year;
- Reductions in electricity production in excess of 1 billion kilowatt-hours per year, or in excess of 500 megawatts of installed capacity;
- Increases in the cost of energy production in excess of 1 percent;
- Increases in the cost of energy distribution in excess of 1 percent;
- Significant increases in dependence on foreign supplies of energy; or
- Having other similar adverse outcomes, particularly unintended ones.

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[103] Executive Order 13211 was issued May 18, 2002. The OMB later released an Implementation Guidance memorandum on July 13, 2002.

PHMSA assessed the potential for the proposed rule to increase the cost of natural gas distributed to end consumers. As presented in section 4, the proposed rule is estimated to have total annualized compliance costs ranging between $740 million and $880 million at a 3 percent discount, and between $753 million and $900 million at a 7 percent discount, depending on assumptions regarding leak incidence rates in distribution pipes.

The proposed rule costs annualized at 7 percent translate into $0.03 per thousand cubic foot when allocated over the volume of natural gas that was delivered to consumers in 2020 (27,727,489 MMcf; Energy Information Administration, 2021). Assuming that these costs are passed through to all consumer types uniformly, they would represent a 0.3 percent increase over the national average price of gas delivered to residential consumers, which was $10.84 per Mcf in 2020 (Energy Information Administration, 2021). For the average residential customer consuming 79 Mcf of natural gas per year, this is equivalent to an increase of $2.15 to $2.56 per year.[104]

Given these very small cost increases, which are well below the thresholds of concern specified by OMB, PHMSA concludes that the proposed rule would not have a *significant adverse effect* at a national or regional level under Executive Order 13211.

8.3 Executive Orders 12898 and 14008: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations and Tackling the Climate Crisis at Home and Abroad

Executive Order 12898 (59 FR 7629, February 11, 1994) requires that, to the greatest extent practicable and permitted by law, each Federal agency must make the achievement of environmental justice (EJ) part of its mission. Executive Order 12898 provides that each Federal agency must conduct its programs, policies, and activities that substantially affect human health or the environment in a manner that ensures such programs, policies, and activities do not have the effect of (1) excluding persons (including populations) from participation in, or (2) denying persons (including populations) the benefits of, or (3) subjecting persons (including populations) to discrimination under such programs, policies, and activities because of their race, color, or national origin.

Executive Order 14008 (86 FR 7619, February 1, 2021) expands on the policy objectives established in Executive Order 12898 and directs federal agencies to develop programs, policies, and activities to address the disproportionately high and adverse human health, environmental, climate-related and other cumulative impacts on disadvantaged communities, as well as the accompanying economic challenges of such impacts.

To meet the objectives of Executive Orders 12898 and 14008, and consistent with DOT guidance on considering EJ in the development of regulatory actions, PHMSA assessed whether the benefits of the proposed rule may be differentially distributed among population subgroups in the affected areas. Due to gaps in the data necessary to delineate the service areas of each affected

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104 Average natural gas consumption per residential customer is based on 2019 statistics which show total consumption by the residential sector of 5,015,603 MMcf by 63,519,734 residential customers (Energy Information Administration, 2021).

pipeline operator, PHMSA was not able to identify and characterize individual communities that may be most directly affected by natural gas leaks and instead conducted a qualitative assessment of the proposed rule with respect to EJ. PHMSA will continue to review available data to assess the feasibility of conducting more detailed analyses of EJ considerations associated with this action.

The proposed rule is expected to significantly reduce methane emissions that contribute to climate change. The climate change impacts of methane emissions extend far beyond their sources and affect communities that do not necessarily live close to the pipelines. Numerous studies and scientific assessments have demonstrated that poorer or predominantly non-White communities and other groups that historically have been disproportionally affected by environmental stressors, also face disproportionate risks from climate change (Intergovernmental Panel on Climate Change, 2014a; EPA, 2021c; U.S. Global Change Research Program, 2018a). Some communities of color, specifically populations defined jointly by ethnic/racial characteristics and geographic location, may be uniquely vulnerable to climate change health impacts in the U.S. These communities live in areas where the impacts of climate change (*e.g.*, extreme temperatures, flooding) may be the greatest, and they tend to have limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies or have less access to social and information resources. In particular, the 2016 scientific assessment on the *Impacts of Climate Change on Human Health* found with high confidence that vulnerabilities are place- and time-specific, life stages and ages are linked to immediate and future health impacts, and social determinants of health are linked to greater extent and severity of climate change-related health impacts (USGCRP, 2016).

Additionally, to the extent that historically marginalized and overburdened communities are located in proximity to leaking regulated natural gas gathering, transmission, and distribution lines, they will benefit from more timely discovery and repairs of leaking pipes and lower risk of accidents and other consequences. A study by Emanuel *et al.* (2021) has showed a positive correlation between county-level density of natural gas gathering and transmission pipelines and an index of social vulnerability that accounts for demographic (*e.g.*, racial composition, age distribution) and socioeconomic factors. Their analysis suggests that environmental, health, and other burdens associated with the gas pipeline infrastructure are shouldered disproportionately by communities that have a limited capacity to carry such loads. As such, these communities may receive environmental and health benefits from reductions in tropospheric ozone levels, which methane emissions contribute to, as well as safety benefits.

For these reasons, PHMSA finds that this rule helps advance the policy objectives enunciated in Executive Orders 12898 and 14008.

8.4 Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999) requires PHMSA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." Policies that have federalism implications are defined in the Executive Order to include regulations that 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."

Under section 6 of Executive Order 13132, PHMSA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute unless the federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments or unless PHMSA consults with State and local officials early in the process of developing the regulation. PHMSA also may not issue a regulation that has federalism implications and that preempts State law, unless the Agency consults with State and local officials early in the process of developing the regulation.

PHMSA assessed that this action will not have federalism implications. The proposed rule does not preempt state law. As discussed in the NPRM, this proposed rule is directly mandated by the PIPES Act of 2020. PHMSA anticipates that the final rule will not impose a significant incremental administrative burden on States from issuing, reviewing, and overseeing compliance with leak detection and repair requirements. With respect to direct compliance costs, PHMSA recognizes that the proposed rule is estimated to impose incremental costs on local governments that operate municipal gas distribution systems, and that the Federal government will not provide the funds necessary to pay those costs. Specifically, PHMSA has identified 1,007 operators owned by local government and other non-federal government entities; 912 of these government entities operate gas distribution systems and 164 entities operate gas gathering or transmission systems.[105]

However, the costs of the proposed rule are not expected to have a material impact on budgets of government entities operating distribution systems because of the expectations that incremental compliance costs may be passed on to customers through what would be small increases in higher natural gas rates (see section 8.2 for estimates of the potential rate impacts). While operators of gathering and transmission pipelines may not have the same ability to pass through cost increases, the compliance costs are very small both relative to natural gas rates (see section 8.2) and on a per entity basis; the average annualized compliance cost to a government entity operating gas gathering and transmission pipeline is approximately $87,000.[106, 107]

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105 See section 7.2 for details on the distribution of regulated systems and operators by entity type. An estimated 1,008 operators owned by government entities are potentially affected by the proposed rule requirements. One of these operators is owned by the federal government (Air Force Base) and the remainder are owned by municipal and county governments.

106 The average cost per operator reflects costs of complying with requirements specific to gas gathering and transmission. Some government entities operate gathering, transmission, and distribution pipelines.

107 As discussed in section 3.1.3, there is uncertainty on the number of operators associated with Type C gathering lines since they have not been required to report to PHMSA until recently. For this analysis, PHMSA assumed that the same operators who operate Type A and Type B gathering lines also operate Type C gathering lines and distributed Type C gathering pipelines mileage (and associated compliance costs) to the known operators. This approach overstates impacts of the proposed rule on these operators in the event that Type C gathering pipelines are instead operated by other firms.

8.5 Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act (UMRA) of 1995, 2 U.S.C. 1501 et seq., establishes significance thresholds for the direct costs of regulations on State, local, or Tribal governments or the private sector that trigger certain agency reporting requirements. The statutory thresholds established in UMRA were $50 million for intergovernmental mandates and $100 million for private-sector mandates in 1996. According to the Congressional Budget Office, the thresholds for 2021, which are adjusted annually for inflation, are $85 million and $170 million, respectively, for intergovernmental and private-sector mandates.

PHMSA analyzed the distribution of costs across the different types of entities that own and operate pipeline systems to provide insight on the potential compliance burden to government entities (*i.e.*, State and local governments) that own or operate pipeline systems, and to small government entities specifically, as well as to privately-owned entities. This analysis uses the ownership and size categories described in section 6, and the annualized costs of the proposed rule at a 7 percent discount rate. These costs are $752 million to $899 million per year (the estimated annualized costs are $739 million to $878 million at a 3 percent discount).

As summarized in Table 69, PHMSA identified 1,008 municipal or other government entities that own pipeline systems (986 municipal and 22 other government, including the federal government). Of these entities, 959 are small governments (950 municipal governments and 9 other governments). As shown in Table 70 the total costs to government entities range between $67 million and $96 million, depending on the assumed distribution main leak incidence rate, whereas the total costs to private entities (including cooperatives) range between $687 million and $805 million. The annual compliance costs tend to be smaller, on average, for governments than for private entities, and also tend to be smaller for small governments than for large governments.

Table 69: Number of owning entities and pipeline system operators by ownership structure and entity size

Entity type	Number of entities			Number of pipeline operators	
	Small	Large	Total	Gathering and transmission	Distribution
Municipal	950	36	986	156	896
Other government	9	13	22	8	17
Investor-owned/private	893	481	1,374	1,141	386
Cooperative	20	3	23	3	23
Total	**1,872**	**533**	**2,405**	**1,308**	**1,322**
Source: PHMSA analysis					

Table 70: Total and average annualized costs of the proposed rule by ownership structure and entity size (million 2020$; 7% discount rate)

Entity type	Total annualized compliance costs (million 2020$)			Average annualized compliance costs (million 2020$/entity)		
	Small	Large	Total	Small	Large	Total
Estimate basis	**Low[1]**					
Municipal	$36.2	$27.3	$64	$0.04	$0.76	$0.06
Other government	$0.7	$2.5	$3	$0.08	$0.19	$0.15
Investor-owned/private	$121.0	$563.0	$684	$0.14	$1.17	$0.50
Cooperative	$1.0	$1.5	$3	$0.05	$0.52	$0.11

Table 70: Total and average annualized costs of the proposed rule by ownership structure and entity size (million 2020$; 7% discount rate)						
Entity type	**Total annualized compliance costs (million 2020$)**			**Average annualized compliance costs (million 2020$/entity)**		
	Small	**Large**	**Total**	**Small**	**Large**	**Total**
Total[2]	**$159.0**	**$594.4**	**$753**	**$0.08**	**$1.12**	**$0.31**
Estimate basis	**High[1]**					
Municipal	$54.0	$37.3	$91	$0.06	$1.04	$0.09
Other government	$1.3	$3.1	$4	$0.15	$0.24	$0.20
Investor-owned/private	$136.3	$663.9	$800	$0.15	$1.38	$0.58
Cooperative	$1.9	$2.4	$4	$0.10	$0.81	$0.19
Total[2]	**$193.5**	**$706.8**	**$900**	**$0.10**	**$1.33**	**$0.37**

[1] 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] Total may not add up due to independent rounding.
Source: PHMSA analysis

PHMSA considered alternatives to the requirements proposed in the NPRM, including annual surveys of all distribution systems and maintaining the current 5-year survey interval for plastic pipes. The annual survey alternative produced higher benefits but at much higher cost for affected entities. The 5-year interval for plastic pipes alternative produced lower costs, but was the only scenario that produced net costs rather than net benefits. PHMSA has preliminarily concluded that the proposed alternative produced the best balance of burden vs. benefits.

8.6 Paperwork Reduction Act of 1995

The Paperwork Reduction Act of 1995 (PRA) (superseding the PRA of 1980) is implemented by OMB and requires that agencies submit a supporting statement to OMB for any information collection that solicits the same data from more than nine parties. The PRA seeks to ensure that Federal agencies balance their need to collect information with the paperwork burden imposed on the public by the collection.

The definition of "information collection" includes activities required by regulations, such as permit development, monitoring, record keeping, and reporting. The term "burden" refers to the "time, effort, or financial resources" the public expends to provide information to or for a Federal agency, or to otherwise fulfill statutory or regulatory requirements. PRA paperwork burden is measured in terms of annual time and financial resources the public devotes to meet one-time and recurring information requests (44 U.S.C. 3502(2); 5 C.F.R. 1320.3(b)). Information collection activities may include: reviewing instructions; using technology to collect, process, and disclose information; adjusting existing practices to comply with requirements; searching data sources; completing and reviewing the response; and transmitting or disclosing information.

Agencies must provide information to OMB on the parties affected, the annual reporting burden, the annualized cost of responding to the information collection, and whether the request significantly impacts a substantial number of small entities. An agency may not conduct or sponsor, and a person is not required to respond to, an information collection unless it displays a currently valid OMB control number.

OMB has previously approved the information collection requirements contained in the existing regulations under the provisions of the PRA. The approved collections include:

- National Pipeline Mapping System Program: OMB Control Number 2137-0596
- Annual Report — Gas Distribution System: OMB Control Number 2137-0629
- Annual Report — Natural and Other Gas Transmission and Gathering Pipeline Systems: OMB Control Number 2137-0522
- Annual Report – Type R (Reporting-Regulated) Gas Gathering Pipeline Systems: OMB Control Number 2137-0522
- Annual Report – UNGS: OMB Control Number 2137-0522
- Annual Report – LNG: OMB Control Number 2137-0522
- Incident Report — Gas Distribution System: OMB Control Number 2137-0635
- Incident Report — Gas Transmission and Gathering Systems: OMB Control Number 2137-0522
- Incident Report — LNG Facilities: OMB Control Number 2137-0635
- Incident Report — Type R (Reporting-Regulated) Gas Gathering Pipeline Systems: OMB Control Number 2137-0522
- Reporting Safety-Related Conditions on Gas, Hazardous Liquid, and Carbon Dioxide Pipelines and Liquefied Natural Gas Facilities: OMB Control Number 2137-0578
- Record keeping Requirements for Gas Pipeline Operators: OMB Control Number 2137-0049

As discussed in sections 4.1.4, 4.1.5, 4.3.1, and 4.2.3 the proposed rule will result in several change in the information collection requirements associated with the NPMS, annual reports, incident reports, and requests for exemption or notifications, as well as require the development or revisions to written procedures and maintenance of records of inspection and repairs, among others.

All entities affected by the reporting and recordkeeping requirements are subject to 49 CFR Part 191 and Part 192 requirements in the baseline. Accordingly, PHMSA does not anticipate the overall number of respondents to increase because of this proposed rule, but respondents may incur a higher response burden. Table 71 summarizes the number of respondents and total incremental burden hours for data collection activities covered under the ICR and for new data collection activities. For additional details, see sections 4.1.4 and 4.1.5 (gas gathering and transmission), section 4.3.1 (other gas facilities), and section 4.2.3 (gas distribution).

Table 71: Number of respondents and total annual reporting burden for the proposed rule

Segment	Total number of respondents	Total annual burden (hours/year)[1]	Annualized costs (million 2020$)	
			3% Discount	7 % Discount
Gathering and transmission[2]	1,308	64,192	$3.4	$3.8
Distribution	1,322	25,779	$2.4	$2.6
Other gas facilities	214	108	<$0.1	<$0.1
Total	**2,844**	**90,079**	**$5.9**	**$6.5**

Table 71: Number of respondents and total annual reporting burden for the proposed rule				
Segment	Total number of respondents	Total annual burden (hours/year)[1]	Annualized costs (million 2020$)	
			3% Discount	7 % Discount

[1] Total burden hours include activities that are conducted only once and activities that are conducted annually or on an as needed basis. For activities conducted only once, PHMSA divided the total hours by the period of analysis (15 years)
[2] Includes NPRM reporting requirements for regulated gas gathering (section 4.1.4) as well as other reporting and recordkeeping requirements for gathering transmission pipelines (section 4.1.5).
Source: PHMSA analysis

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Appendix A Modeling Framework

A.1 Natural Gas Gathering and Transmission Leak Detection and Repair Costs-Benefits Model

The framework tracks pipeline mileage over time (each year), the incidence and emissions of detected leaks, miles surveyed at the required frequency, and the costs of patrols, surveys, and repairs. Calculations are performed over a 15-year period of analysis. PHMSA performs the analysis for the baseline and proposed rule scenarios and takes the difference between the two scenarios as attributable to the rule.

The calculations entail the following steps for onshore pipelines:[108]

- **Obtaining the pipeline mileage for the current year**. The pipeline mileage by class and sector (*i.e.*, transmission, gathering) over time is based on trends reported in 2015-2020 annual reports. PHMSA performs the analysis by class but also tracks certain sub-categories of pipeline relevant to the rule requirements: percentage of pipeline in HCAs, miles of odorized pipeline (assumed to be Class 3 and Class 4 intrastate transmission lines), and miles of leak prone pipe (assumed to be bare steel lines). For Type C gas gathering lines, PHMSA uses the 2021 mileage estimates and grows this mileage at a rate of 1.3 percent per year over the period of analysis, based on the same growth rate PHMSA used in the analysis of the Expansion of Gas Gathering Regulation (PHMSA, 2021c).
- **Estimating the number of leaks per mile and methane emissions per leak**. The leak incidence rate (leaks/mile-year) in the baseline is estimated based on the number of leaks and total pipeline mileage reported in PHMSA annual reports (2015-2020 average). PHMSA combined this with the methane emission factors for gathering and boosting pipeline leaks (288.5 kg/mile) and transmission and storage pipeline leaks (10.9 kg/mile) from EPA's GHGI to estimate the leak emissions rate (metric ton/leak-year). To calculate the number of leaks discovered under the proposed rule, PHMSA assumed that current survey practices have a relative effectiveness of 85 percent when compared to the number of leaks that could be discovered using ALD methods in accordance with the proposed rule (EPA, 1996; PHMSA best professional judgment [BPJ]).
- **Estimating patrol unit costs**. PHMSA estimated the cost of conducting patrols on transmission and gathering lines at $32 to $128 per mile, following the economic analysis for the expansion of regulated gas gathering (PHMSA, 2021c). The costs depend on whether the additional patrols are added to an existing program or are part of a new program; for this analysis, PHMSA used the higher estimate.[109]
- **Estimating leakage survey costs**. PHMSA assumes leak surveys cost for onshore pipelines is $515 per mile (Southern California Gas Company, 2014; PHMSA, 2021c).

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108 As discussed in sections 4.1.1 and 4.1.2, PHMSA does not expect proposed requirements for offshore pipelines to result in incremental costs when considering baseline patrolling and gas survey practices.

109 Patrol costs were adjusted from their original estimates in 2018 dollars ($31 to $124) to 2020 dollars using the GDP deflator (1.03).

- **Estimating leak repair costs**. The average unit repair cost used in the analysis for leaks on transmission and gathering lines ($5,868/leak) is based on data supporting utility rate cases for transmission services ($5,650/leak, based on data from Pacific Gas and Electric Company, 2019b), plus the estimated cost of conducting a follow-up inspection to confirm the effectiveness of the repair ($218, based on 4 hours of a technician's time).
- **Estimating avoided emissions**. PHMSA estimates avoided emissions for the current year based on the number of leaks detected mid-year (for leaks detected as part of a leak survey program requiring surveys two or more times per year) and cumulative emission reductions for leaks repaired in previous years, as these leaks would otherwise continue to emit methane. PHMSA assumes that all leaks detected as part of an annual leak survey program would be detected and repaired at the end of the year, with emissions reductions realized beginning in the following year. These calculations are done for both the baseline and proposed rule scenarios, with the difference between the two scenarios indicative of the benefits of the proposed rule. These avoided emissions are used to estimate benefits based on the social cost of carbon and avoided natural gas losses.
- **Distributing regulated Type C gas gathering line costs to operators**. To support analyses informing RFA and UMRA considerations, PHMSA distributes the costs associated with regulated Type C gas gathering lines to individual operators in proportion to their share of the reported Type A and B gas gathering and gas transmission pipeline mileage.

Table 72 summarizes key assumptions used in the calculations.

Table 72: Key assumptions used in the calculations of natural gas gathering and transmission leak detection and repair costs and benefits.

Parameter	Value	Notes
Analysis year	2024	Assumed effective year of the proposed rule. All costs and benefits are calculated over a 15-year period (through 2038) and discounted back to 2024.
Fraction of pipelines in HCAs	7% (transmission), 0% (gathering)	Non-exempted (*e.g.*, non-leak prone) pipeline in HCAs are required to perform more frequent leak surveys in the policy case. The assumption is based on annual report data. Operators must report the miles of pipelines in HCAs, the miles of pipelines by class location, and the miles of pipelines by material, but not combinations of those parameters. PHMSA therefore had to make assumptions regarding the joint distributions. PHMSA first divided mileage into leak prone (bare steel) and non-leak prone, then applied the % by class and/or % HCA/non-HCA. PHMSA applies this fraction uniformly across all classes.
COSTS AND SURVEY EFFECTIVENESS		
Patrolling costs	$218/mile	Unit costs obtained from the economic analysis for the expansion of regulated gas gathering ($36 to $218 per mile, PHMSA, 2021c). PHMSA used the higher value assuming that the additional patrols would be part of a new program. Operators of gas transmission and Type A gas gathering pipelines are assumed to perform patrols at least once per month in the baseline under current practice (PHMSA BPJ) and therefore there are zero incremental costs for patrol requirements under the proposed rule. Operators are assumed not to patrol Type B and Type C gas gathering lines in the baseline. Operators will conduct monthly visual patrols of Type B and Type C gas gathering lines, with one of the monthly patrols performed as part of the required annual leakage survey. PHMSA therefore estimated incremental costs based on 11 patrols (plus the leakage survey costs above).

<table>
<tr><th colspan="3">Table 72: Key assumptions used in the calculations of natural gas gathering and transmission leak detection and repair costs and benefits.</th></tr>
<tr><th>Parameter</th><th>Value</th><th>Notes</th></tr>
<tr><td>Survey unit costs</td><td>$515/mile</td><td>Applied uniformly to all pipeline, in the baseline and policy cases. Value is based on rate case by SoCalGas and reflects surveys performed using a combination of ground and aerial resources (Southern California Gas Company, 2014; PHMSA, 2021c). PHMSA adjusted the original costs of $500 per mile from 2018 dollars to 2020 dollars using the GDP implicit price deflator (1.03).</td></tr>
<tr><td>Repair unit costs</td><td>$5,868/leak</td><td>Based on information supporting PG&E rate case for transmission services (Pacific Gas and Electric Company, 2019b) and 4 hours of a technician’s time to conduct a follow-up inspection to confirm the effectiveness of the repair.</td></tr>
<tr><td>Effectiveness of current leak surveys</td><td>85%</td><td>Based on long-standing values (EPA, 1996). Effectiveness is expressed relative to leaks discoverable with leak surveys using ALD methods. See section 6.3 for sensitivity analysis around this parameter.</td></tr>
<tr><td>Effectiveness of leak surveys under policy case</td><td>100%</td><td>Effectiveness is expressed relative to leaks discoverable with leak surveys using ALD methods. See section 6.3 for sensitivity analysis around this parameter.</td></tr>
<tr><td>Regulated Type C gathering lines subject to leakage surveys in the baseline</td><td>20,336 miles</td><td>Represents the 2021 mileage. This mileage is assumed to grow at rate of 1.3% per year over the period of analysis. Based on estimates included in the Expansion of Gas Gathering Regulation RIA (PHMSA, 2021c)</td></tr>
<tr><td>Regulated Type C gathering lines not subject to leakage surveys in the baseline</td><td>70,527 miles</td><td>Represents the 2021 mileage. PHMSA grows this mileage at a rate of 1.3% per year over the period of analysis, based on the same estimates previously used in the analysis of the Expansion of Gas Gathering Regulation (PHMSA, 2021c).</td></tr>
<tr><td>Fraction of Regulated Type C gathering lines surveyed voluntarily</td><td>0%</td><td>Consistent with the Expansion of Gas Gathering Regulation analysis, PHMSA assumed that existing gas gathering operators do not currently conduct leakage surveys on previously unregulated pipelines (PHMSA, 2021c)</td></tr>
<tr><td>Patrol frequency</td><td>12 per year</td><td>Assume all operators perform monthly patrols on all lines in baseline and policy cases (PHMSA BPJ)</td></tr>
<tr><td>Baseline leak survey frequency</td><td>Surveys per year; see table in “Notes” column</td><td>Based on current reg text; assume intrastate lines are odorized, interstate lines are not odorized
<table>
<tr><th></th><th>Without odorant</th><th>All other lines</th></tr>
<tr><td>Class 1</td><td>1</td><td>1</td></tr>
<tr><td>Class 2</td><td>1</td><td>1</td></tr>
<tr><td>Class 3</td><td>2</td><td>1</td></tr>
<tr><td>Class 4</td><td>4</td><td>1</td></tr>
</table></td></tr>
<tr><td>Policy case leak survey frequency</td><td>Surveys per year; see table in “Notes” column</td><td>Based on proposed rule reg text; assume bare steel pipe is “leak prone” (PHMSA annual reports show no cast iron transmission or part 192-regulated gathering line mileage)
<table>
<tr><th rowspan="2"></th><th rowspan="2">Leak prone pipe or pipe in HCA</th><th colspan="2">All other (non-leak prone, non-HCA)</th></tr>
<tr><th>Odorized</th><th>Non-odorized</th></tr>
<tr><td>Class 1</td><td>2</td><td>1</td><td>1</td></tr>
<tr><td>Class 2</td><td>2</td><td>1</td><td>1</td></tr>
<tr><td>Class 3</td><td>2</td><td>1</td><td>2</td></tr>
<tr><td>Class 4</td><td>4</td><td>1</td><td>4</td></tr>
</table></td></tr>
<tr><th colspan="3">Leak characteristics</th></tr>
<tr><td>Leak incidence rate</td><td>0.0045 leaks/mile-year (transmission)

0.0253 leaks/mile-year (gathering)</td><td>Based on number of natural gas leaks and total mileage reported in PHMSA Annual Reports (2015-2020 average)

See section 6.2 for alternative estimates of leak incidence and emissions rates for gathering lines.</td></tr>
</table>

<table>
<tr><th colspan="3">Table 72: Key assumptions used in the calculations of natural gas gathering and transmission leak detection and repair costs and benefits.</th></tr>
<tr><th>Parameter</th><th>Value</th><th>Notes</th></tr>
<tr><td>Leak emissions rate</td><td>2.4 metric ton CH_4/leak-year (transmission)

11.4 metric ton CH_4/leak-year (gathering)</td><td>Based on EPA GHGI methane emissions factors (10.9 kg/mile for transmission pipeline leaks; 288.5 kg/mile for gathering and boosting pipeline leaks) and leak incidence rate (EPA, 2022a).

See section 6.2 for alternative estimates of leak incidence and emissions rates for gathering lines.</td></tr>
<tr><th colspan="3">Repairs</th></tr>
<tr><td>Share of leaks repaired immediately</td><td>100%</td><td>Based on PHMSA BPJ; repair schedule based on leak survey frequency as follows:
<table>
<tr><td>Survey frequency (surveys per year)</td><td>1</td><td>2</td><td>4</td></tr>
<tr><td>Fraction of leaks repaired in Q1</td><td>0</td><td>0</td><td>0.25</td></tr>
<tr><td>Fraction of leaks repaired in Q2</td><td>0</td><td>0.5</td><td>0.25</td></tr>
<tr><td>Fraction of leaks repaired in Q3</td><td>0</td><td>0</td><td>0.25</td></tr>
<tr><td>Fraction of leaks repaired in Q4</td><td>1</td><td>0.5</td><td>0.25</td></tr>
</table></td></tr>
<tr><th colspan="3">Benefit quantification</th></tr>
<tr><td>Social cost of methane</td><td>Varies over time</td><td>Based on the February 2021 interim values (e.g., $1,500/metric ton in 2021 at 3 percent; $690/metric ton in 2021 at 5 percent) (Interagency Working Group on Social Cost of Greenhouse Gases, 2021)</td></tr>
<tr><td>Value of natural gas loss</td><td>Varies over time</td><td>Based on projected Henry Hub spot prices from the Energy Information Administration’s Annual Energy Outlook 2021 (U.S. Energy Information Administration, 2021).</td></tr>
</table>

A.2 Natural Gas Distribution Leak Detection and Repair Costs-Benefits Model

Figure 7 illustrates the framework PHMSA used to model distribution system leak detection and repair under the baseline conditions. The framework tracks quantities over time (each year) of the mileage of distribution mains, the incidence and inventory of leaks in that pipeline network, surveyed mains, leaks discovered, grading of discovered leaks, and repairs or monitoring of known leaks. Calculations are performed over a 15-year period of analysis for each system (defined as a unique combination of operator and state) and mains material. Figure 8 illustrates how PHMSA applied the framework to model conditions following implementation of the proposed rule. A key difference for the proposed rule, other than the values of certain input parameters, is the assignment of certain leaks previously classified as grade 3 (G3) in the baseline to the grade 2 (G2) category subject to the 6-month repair deadline. PHMSA performs the analysis for the baseline and proposed rule scenarios and takes the difference between the two scenarios as attributable to the rule.

The calculations entail the following steps:

- **Obtaining the pipeline mileage for the current year**. The main mileage by operator and material changes over time based on operator and material-specific trends reported in 2015-2020 annual reports (*e.g.,* replacement of cast iron with plastic). (*Note that the calculations do not differentiate based on age of the pipes*)
- **Estimating the number of leaks present in the distribution system**. This quantity is the inventory of leaks present in the current year, starting from the count at the end of the prior year to which PHMSA adds new leaks forming in the current year. The number of additional leaks for the current year is estimated based on material-specific leak incidence rates (#

leak/mile) from Lamb *et al.* (2015) or Weller *et al.* (2020), which PHMSA normalized to an annual basis (# leak/mile-year) assuming that the respective studies reflected the applicable baseline survey intervals for each material. In the analysis, 100 percent of leaks corresponds to estimates developed from Lamb *et al.* (2015) or Weller *et al.* (2020) and therefore reflect the leak detection methods employed in these studies.[110]

- **Estimating the number of miles surveyed.** The mileage surveyed is based on state- and material-specific survey intervals. State-specific intervals are used if more stringent than federal requirements (*e.g.*, CT and MA). For all other states, PHMSA uses federal requirements. PHMSA assumes uniform distribution of surveys over the pipeline network, *e.g.*, an operator with 300 miles of mains subject to an interval of 3 years is assumed to survey 100 miles of mains per year.
- **Estimating the number of leaks discovered**. Leak discovery is a function of the mileage surveyed and survey effectiveness, where survey effectiveness is relative to the methods used in the studies on which the incidence rate is based, *e.g.*, 85 percent effectiveness means that the survey will discover 85 percent of leaks that would have been discovered by Lamb *et al.* (2015) or Weller *et al.* (2020). PHMSA assumes the same survey effectiveness across all leak grades.
- **Dividing the leaks by grade**. PHMSA assumes a uniform proportion of leaks discovered are grades 1 and 2 (G1&G2) vs. grade 3 (G3).
- **Determining the number of leaks repaired within the year vs. scheduled for future repair**. PHMSA assumes that leaks in the G1&G2 category are repaired in the year they are discovered. PHMSA further assumes that a specified fraction of G3 leaks is repaired in the year discovered and the balance of G3 leaks are scheduled for future repairs according to the applicable repair deadline. State-specific repair deadlines are used if more stringent than federal requirements (*e.g.*, CA and MA).
- **Estimating leak repair costs**. PHMSA calculates repair costs for the current year by multiplying the unit repair costs by the number of leaks repaired in the current year. The number of leaks repaired in the current year is equal to G1&G2 leaks discovered plus G3 leaks discovered in the current year and repaired immediately or discovered in earlier years and scheduled for repair in the current year based on the repair deadline.

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110 PHMSA assumed that lines surveyed by Weller *et al.* (2020) were equally likely to have been surveyed in any of the years within the applicable survey intervals from the 49 CFR requirements and adjusted the rates to an equivalent annual leak incidence. As an example, if mains are generally surveyed every 5 years and x is the annual leak incidence rate per mile, then there is a 0.2 probability of having x leaks, 0.2 probability of having $2x$ leaks, 0.2 probability of having $3x$ leaks, 0.2 probability of having $4x$ leaks, and 0.2 probability of having $5x$ leaks on a given mile. The expected number of leaks ($3x$) is then set equal to the value from Weller *et al.* (2020) and the equation is solved for x; *i.e.*, x is equal to the value in Weller *et al.* (2020) times 1/3. Going from 3-year to 1-year surveys involves similar calculations. There is a 0.333 probability of having each of $1x$, $2x$, or $3x$ leaks on a given mile, with an expected number of leaks of $2x$. Setting this expected value equal to the rate in Weller *et al.* (2020) and solving for x means that x is the rate in Weller *et al.* (2020) divided by 2.

- **Estimating leak monitoring costs**. PHMSA calculates monitoring costs by multiplying the unit monitoring costs by the number of G3 leaks in the current inventory (not including leaks repaired in the current year).
- **Updating the inventory of leaks.** PHMSA estimates the inventory of leaks at the end of the current year to reflect leaks repaired in the current year. This becomes the starting inventory of leaks for the next year.
- **Estimating avoided emissions**. PHMSA estimates avoided emissions for the current year based on cumulative leak repairs performed up to the current year and material-specific emission factors from Lamb *et al.* (2015) or Weller *et al.* (2020). These avoided emissions are used to estimate benefits based on the social cost of carbon and avoided natural gas losses.

Table 73 summarizes key assumptions used in the calculations.

Figure 7: Modeling of leak detection and repair under baseline conditions.

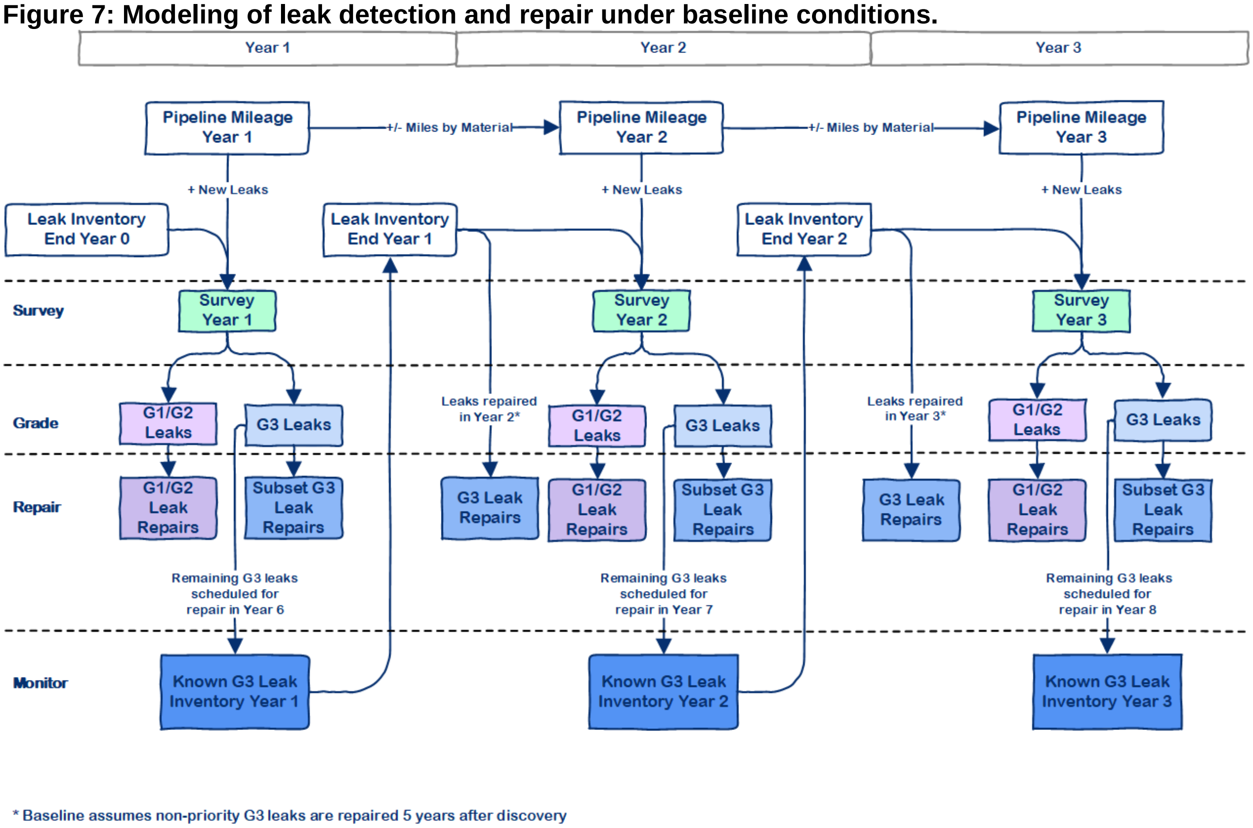
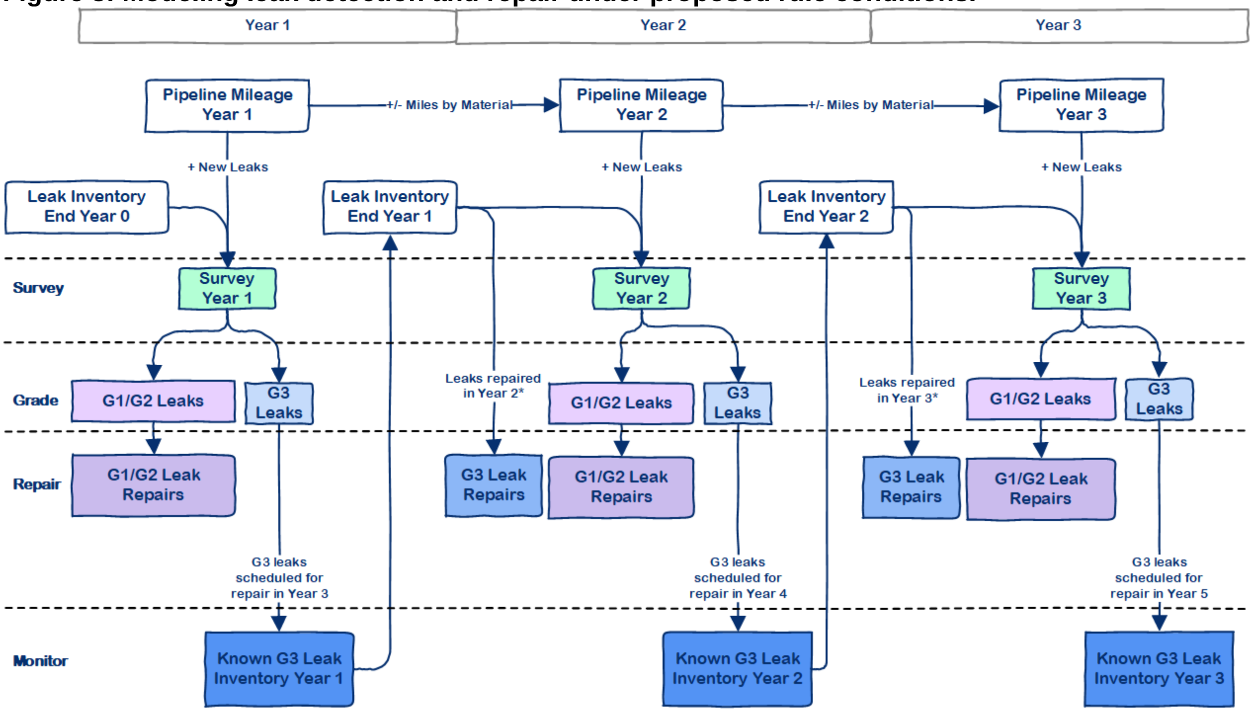


Figure 8: Modeling leak detection and repair under proposed rule conditions.



* Proposed rule upgrades certain leaks previously classified as G3 to G2 and assumes remaining G3 leaks are repaired 2 years after discovery

Table 73: Key assumptions used in the calculations of natural gas distribution leak detection and repair costs and benefits.

Parameter	Value	Notes
Analysis year	2024	Assumed effective year of the proposed rule. All costs and benefits are calculated over a 15-year period (through 2038) and discounted back to that year.
Fraction of mains in business districts	5%	Applied uniformly across all operators and materials. Mains in business districts are assumed to be surveyed annually under both the baseline and proposed rule.
Fraction of “historic” plastic mains	0%	Share is unknown but is assumed to be small.
Costs and survey effectiveness		
Survey unit costs, current practices	$1,370/mile	Applied uniformly to all operators and materials. Value is the average of unit survey costs documented in rate cases and mitigation plans: $1,245/mile and $1,490 per mile (Southern California Gas Company, 2020; Pacific Gas and Electric Company, 2018). The costs represent surveys conducted using combination of mobile and hand-held methods, including some ALD methods. The costs include surveys of associated services.
Survey unit costs, with ALD	$1,370/mile	Applied uniformly to all operators and materials. Assumed equal to cost of current practices since programs described in current practices already include some ALD implementation.
Repair unit costs	$4,300/leak	Applied uniformly to all G3 leaks. Based on rate cases and mitigation plans which show unit costs ranging from $3,000/leak to $6,500 per leak (Southern California Gas Company, 2020; Pacific Gas and Electric Company, 2018)

Table 73: Key assumptions used in the calculations of natural gas distribution leak detection and repair costs and benefits.

Parameter	Value	Notes
Repair follow-up unit costs	$109/leak	Based on PHMSA BPJ that the post-repair inspection requires 2 hours to mobilize, get to the location, monitor the leak, and document. Reflects national average loaded hourly wages of surveying and mapping technicians ($54.49/hour) (Bureau of Labor Statistics, 2020, 2021a; U.S. Bureau of Labor Statistics, 2021).
Monitoring unit costs	$109/leak	Based on PHMSA BPJ that monitoring leaks require 2 hours to mobilize, get to the location, monitor the leak, and document. Reflects national average loaded hourly wages of surveying and mapping technicians ($54.49/hour) (Bureau of Labor Statistics, 2020, 2021a; U.S. Bureau of Labor Statistics, 2021).
Baseline monitoring frequency	1/year	Applies to each G3 leak in the backlog, *i.e.*, known but not yet repaired in the current year.
Proposed rule monitoring frequency	2/year	Applies to each G3 leak in the backlog, *i.e.*, known but not yet repaired in the current year.
Effectiveness of current leak surveys (relative to ALD)	85%	Based on long-standing value (EPA, 1996). Effectiveness is expressed relative to leaks discoverable with leak surveys using ALD methods.
Effectiveness of leak surveys with ALD	100%	Reflect the basis for leak incidence and emissions rates used in the analysis. Effectiveness is expressed relative to leaks discoverable with leak surveys using ALD methods.
Share of mileage to be surveyed due to extreme weather or other conditions	1%	Represents the share of mileage that may need to be surveyed due to extreme weather or other conditions. This share applies to all distribution main mileage.
Share of known leaks to be monitored due to extreme weather or other conditions	5%	Represents the share of known leaks that need to be monitored due to extreme weather or other conditions. This share applies to the inventory of leaks identified to date, but not yet repaired.
Leak characteristics		
G3 propane leaks as share of total propane leaks	100%	Assumes that all propane leaks are classified as hazardous and repaired immediately or prioritized for repair within the year they are identified under both the baseline and the proposed rule. This practically categorizes all propane leaks as G1/G2 for the purpose of the analysis. This assumption reflects the lower flammability limits for propane when compared to natural gas (see Table 1 of the GPTC guide Appendix G-192-11A; GPTC, 2018)
G3 leaks as share of total leaks (for gases other than propane)	60%	Based on leak grading information from annual performance reports of LDCs in MA and NY. The remaining 40 percent of leaks are G1 or G2.
G3 "priority" leaks as share of G3 leaks (for gases other than propane)	15%	Based on leak grading information from annual performance reports of LDCs in MA which requires measurement of G3 leaks to determine whether they exceed the "significant environmental impact" threshold (SEI). PHMSA assumes that the SEI threshold is roughly equivalent to the 10 CFH threshold.
Share of total emissions from G3 "priority" leaks (for gases other than propane)	50%	Based on cumulative emissions curve in Weller *et al.* (2020) (see Figure S9). Corresponds to the share of emissions associated with the 15 percent of largest leaks.
Leak incidence rate	leak/mile (see next column)	Based on Weller *et al.* (2020) (leak/mile):

Material	Per survey	Normalized per year
STEEL_UNP_BARE	0.51	0.26
STEEL_UNP_COATED	0.51	0.26
STEEL_CP_BARE	0.61	0.20
STEEL_CP_COATED	0.61	0.20
PLASTIC	0.43	0.14
CI	1.00	0.50
DI	1.00	0.50
CU	0.51	0.26
RCI	0.43	0.14

<table>
<tr><th colspan="3">Table 73: Key assumptions used in the calculations of natural gas distribution leak detection and repair costs and benefits.</th></tr>
<tr><th>Parameter</th><th>Value</th><th>Notes</th></tr>
<tr><td></td><td></td><td>
<table>
<tr><td>OTHER</td><td>0.51</td><td>0.17</td></tr>
</table>
Based on Lamb et al. (2015) (leak/mile):
<table>
<tr><th>Material</th><th>Per survey</th><th>Normalized per year</th></tr>
<tr><td>STEEL_UNP_BARE</td><td>2.51</td><td>1.26</td></tr>
<tr><td>STEEL_UNP_COATED</td><td>2.51</td><td>1.26</td></tr>
<tr><td>STEEL_CP_BARE</td><td>0.11</td><td>0.04</td></tr>
<tr><td>STEEL_CP_COATED</td><td>0.11</td><td>0.04</td></tr>
<tr><td>PLASTIC</td><td>0.05</td><td>0.02</td></tr>
<tr><td>CI</td><td>2.88</td><td>1.44</td></tr>
<tr><td>DI</td><td>2.88</td><td>1.44</td></tr>
<tr><td>CU</td><td>2.51</td><td>1.26</td></tr>
<tr><td>RCI</td><td>0.05</td><td>0.02</td></tr>
<tr><td>OTHER</td><td>0.23</td><td>0.08</td></tr>
</table>
To normalize leak incidence rates, PHMSA assumed that lines surveyed in each study were equally likely to have been surveyed in any of the years within the applicable survey intervals from the 49 CFR requirements and adjusted the rates to an equivalent annual leak incidence. As an example, if plastic mains are generally surveyed every 5 years and x is the annual leak incidence rate per mile, then there is a 0.2 probability of having x leaks, 0.2 probability of having 2x leaks, 0.2 probability of having 3x leaks, 0.2 probability of having 4x leaks, and 0.2 probability of having 5x leaks on a given mile. The expected number of leaks (3x) is set equal to the value from the study and the equation is solved for x. For this example, x is set equal to the value in Weller et al. (2020) (0.43 leak/mile) times 1/3, which is 0.14 leak/mile. Going from 3-year to 1-year surveys for bare unprotected steel involves similar calculations. There is a 0.333 probability of having each of 1x, 2x, or 3x leaks on a given mile, with an expected number of leaks of 2x. Setting this expected value equal to the rate in Weller et al. (2020) (0.51 leak/mile) and solving for x means that x is the rate in Weller et al. (2020) divided by 2, or 0.26 leak/mile.
</td></tr>
<tr><td>Leak emissions rate for natural gas</td><td>metric tonne CH_4/leak (see next column)</td><td>
Based on Weller et al. (2020) (metric tonne/year-leak):
<table>
<tr><th>Material</th><th>All G3 leaks combined</th><th>Higher-emitting G3 leaks (adjusted)[1]</th><th>Other G3 leaks (adjusted) [1]</th></tr>
<tr><td>STEEL_UNP_BARE</td><td>1.177</td><td>2.907</td><td>0.872</td></tr>
<tr><td>STEEL_UNP_COATED</td><td>1.177</td><td>2.907</td><td>0.872</td></tr>
<tr><td>STEEL_CP_BARE</td><td>1.051</td><td>2.596</td><td>0.779</td></tr>
<tr><td>STEEL_CP_COATED</td><td>1.051</td><td>2.596</td><td>0.779</td></tr>
<tr><td>PLASTIC</td><td>1.067</td><td>2.634</td><td>0.790</td></tr>
<tr><td>CI</td><td>0.904</td><td>2.232</td><td>0.670</td></tr>
<tr><td>DI</td><td>0.904</td><td>2.232</td><td>0.670</td></tr>
<tr><td>CU</td><td>1.177</td><td>2.907</td><td>0.872</td></tr>
<tr><td>RCI</td><td>1.067</td><td>2.634</td><td>0.790</td></tr>
<tr><td>OTHER</td><td>1.051</td><td>2.596</td><td>0.779</td></tr>
</table>
[1] The adjustment of the emission factor for higher-emitting leaks is based on the assumed share of total emissions (50 percent) represented by the assumed share of leaks (15 percent), which implies a higher emission factor per leak than the rest of the distribution.
Based on Lamb et al. (2015) (metric tonne/year-leak):
<table>
<tr><th>Material</th><th>All G3 leaks combined</th><th>Higher-emitting G3 leaks (95th percentile)</th><th>Other G3 leaks</th></tr>
<tr><td>STEEL_UNP_BARE</td><td>0.405</td><td>1.088</td><td>0.405</td></tr>
<tr><td>STEEL_UNP_COATED</td><td>0.405</td><td>1.088</td><td>0.405</td></tr>
<tr><td>STEEL_CP_BARE</td><td>0.636</td><td>2.413</td><td>0.636</td></tr>
<tr><td>STEEL_CP_COATED</td><td>0.636</td><td>2.413</td><td>0.636</td></tr>
<tr><td>PLASTIC</td><td>0.173</td><td>0.352</td><td>0.173</td></tr>
</table>
</td></tr>
</table>

<table>
<tr><th colspan="3">Table 73: Key assumptions used in the calculations of natural gas distribution leak detection and repair costs and benefits.</th></tr>
<tr><th>Parameter</th><th>Value</th><th>Notes</th></tr>
<tr><td></td><td></td><td><table>
<tr><td>CI</td><td>0.473</td><td>1.761</td><td>0.473</td></tr>
<tr><td>DI</td><td>0.473</td><td>1.761</td><td>0.473</td></tr>
<tr><td>CU</td><td>0.405</td><td>1.088</td><td>0.405</td></tr>
<tr><td>RCI</td><td>0.173</td><td>0.352</td><td>0.173</td></tr>
<tr><td>OTHER</td><td>0.636</td><td>2.413</td><td>0.636</td></tr>
</table></td></tr>
<tr><td>Leak incidence rate of other gases</td><td>leak/mile (see next column)</td><td>See tables above.
Assume that the incidence rate for other gases is the same as that for natural gas.</td></tr>
<tr><td>Leak emissions rate for other gases</td><td>metric tonne CH_4/leak (see next column)</td><td>Assume that the emissions rates are equivalent to those for estimated for natural gas based on Weller et al. (2020) and Lamb et al. (2015) but adjusted for differences in the methane content of these other gases (assuming natural gas is 93.4 percent methane).
Assume that landfill gas is distributed after cleaning such that the methane content is the same as that of natural gas.
For synthetic gas, multiply the emissions rates for natural gas by 0.029, based on assumed methane content of 2.5 percent.
For all other gases, assume methane content is 0 percent.</td></tr>
<tr><td>Leak distribution</td><td>% of leaks</td><td>Assume that the distribution of leaks of other gas by size categories are the same as those for natural gas.</td></tr>
<tr><th colspan="3">Repairs</th></tr>
<tr><td>Share of G3 leaks repaired immediately in the baseline</td><td>10%</td><td>Based on annual performance reports of LDCs in MA which provide the date a leak is discovered and date it is repaired. Approximately 9-11 percent of G3 leaks were repaired within a year.
The remaining 90 percent of G3 leaks is assumed to be repaired according to the applicable deadlines.</td></tr>
<tr><td>G1/G2 leak repair deadline</td><td>0 years</td><td>This assumes that G1&G2 leaks are repaired within the year when then are discovered, e.g., a G2 leak discovered in 2024 is assumed to be repaired in 2024.</td></tr>
<tr><td>Baseline G3 leak repair deadline</td><td>5 years</td><td>With the exception of the share above, determines the year when the discovered leaks are assumed to be repaired, e.g., a G3 leak discovered in 2024 is assumed to be repaired in 2029. Uses more stringent applicable state repair deadline, if any.</td></tr>
<tr><td>Proposed rule G3 leak repair deadline</td><td>2 years</td><td>With the exception of the share above and the “priority” leaks re-classified as G2 under the proposed rule definition, determines the year when the discovered leaks are assumed to be repaired, e.g., a G3 leak discovered in 2024 is assumed to be repaired in 2026. Uses more stringent applicable state repair deadline, if any.</td></tr>
<tr><td>Proposed rule backlog repair deadline</td><td>3 years</td><td>Assumes that known leaks identified but not repaired through 2024 will be repaired in 2027.</td></tr>
<tr><th colspan="3">Benefit Quantification and Monetization</th></tr>
<tr><td>Social cost of methane</td><td>Varies over time</td><td>Based on the February 2021 interim values (e.g., $1,500/metric ton in 2021 at 3 percent; $690/metric ton in 2021 at 5 percent) (IWG, 2021)</td></tr>
<tr><td>Value of natural gas loss</td><td>Varies over time</td><td>Based on projected Henry Hub spot prices from the Energy Information Administration’s Annual Energy Outlook 2021 (U.S. Energy Information Administration, 2021).</td></tr>
</table>