Preliminary Regulatory Impact Assessment

Notice of Proposed Rulemaking - Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines

Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
U. S. Department of Transportation

EXECUTIVE SUMMARY

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is proposing to change the Federal pipeline safety regulations in 49 CFR Parts 191 and 192, which cover the transportation of gas by transmission and gathering pipelines. Specifically, PHMSA is proposing to issue new regulations and revise existing regulations to address the following topic areas:

1. Integrity Assessment and Remediation for Segments Outside High Consequence Areas (HCAs) and to re-establish Maximum Allowable Operating Pressure (MAOP)
2. Integrity Management Program Process Clarifications
3. Management of Change
4. Corrosion Control
5. Inspection of Pipelines Following Extreme Events
6. MAOP Exceedance Reports and Records Verification
7. Launcher/Receiver Pressure Relief
8. Expansion of Regulated Gas Gathering Pipelines

This Regulatory Impact Analysis (RIA) provides PHMSA's analysis of the impact of the above topic areas implemented over a 15-year period. Topic Areas 1 through 7 apply to gas transmission pipelines. Topic Area 8 applies to gas gathering pipelines.

ES.1 PROBLEM STATEMENT

The purpose of the proposed rule is to increase the safety of gas pipeline operations. The proposed requirements address safety issues associated with statutory mandates, National Transportation Safety Board (NTSB) recommendations, and Government Accountability Office (GAO) recommendations:

- Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (PL 112-90)
  - Section 5(e) – Allow periodic reassessments to be extended for an additional 6 months if the operator submits sufficient justification.
  - Section 5(a) and (f) – Evaluate whether integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas and, if justified, issue regulations.
  - Section 21 – Regulation of Gas (and Hazardous Liquid) Gathering Lines
  - Section 23 – Regulations to confirm the MAOP of certain pipe with insufficient records and test the material strength of previously untested natural gas transmission pipelines in HCAs
  - Section 29 – Consider seismicity when evaluating pipeline threats
- Government Accountability Office Report GAO-14-667, Department of Transportation Is Taking Actions to Address Rail Safety, but Additional Actions Are Needed to Improve Pipeline Safety, August 2014.
  - The GAO recommended that rulemaking be pursued for gathering lines that addresses the risks of larger-diameter, higher-pressure gathering lines,

including subjecting such pipelines to emergency response planning requirements.

- NTSB Recommendations
    - P-11-14 – Recommendation to PHMSA to amend 49 CFR 192.619 to delete exception and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.
    - P-11-15 – Recommendation to PHMSA to amend 49 CFR Part 192 so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP.
    - P-11-17 – Recommendation to PHMSA to require all natural gas transmission pipelines be configured to accommodate in-line inspection tools, with priority given to older pipelines.
    - P-11-19 – Recommendation to PHMSA to develop and implement standards for integrity management and other performance-based safety programs that require operators to regularly assess the effectiveness of their programs.
    - P-12-3 – Recommendation to PHMSA to revise 49 CFR §195.452 to address engineering assessment, assessment methods, excavation criteria, pressure restriction limits, and acceptable methods for determining crack growth for crack defects in steel pipe.
    - P-14-1 – Recommendation to PHMSA to revise 49 CFR §192.903, Subpart O, to add principal arterial roadways to the list of "identified sites" that establish a High Consequence Area.

These statutory mandates and recommendations stem from a number of high profile and high consequence gas transmission and gathering pipeline incidents and changes in the industry since the establishment of existing regulatory requirements.

ES.2 BASELINE FOR THE ANALYSIS

Current regulations require gas transmission pipeline operators to establish the maximum allowable operating pressure (MAOP) by pressure testing the pipe, with some exemptions, and maintain records documenting the material strength of the pipe. Current regulations require operators of gas transmission pipelines in high consequence areas (HCAs) to assess pipeline integrity (integrity management) every seven years. Operators conduct these assessments through pressure testing, inline inspection, and other inspection techniques. Operators also assess some percentage of pipelines located outside of HCAs, either in conjunction with assessments of HCA pipe or for other reasons. Operators report to PHMSA on pipeline mileage, material documentation records, integrity assessment mileage and methods, incidents that meet a threshold for reporting, and other infrastructure characteristics; these data underlie the analysis of the incremental impact of the proposed rule.

Current regulations apply to only a subset of gas gathering pipeline operations. As a result, PHMSA does not have data on the unregulated portion of this sector. Some operators of gas transmission and existing regulated gas gathering lines may have unregulated gathering lines. These operators may already have many of the operational programs and processes in place. These considerations also underlie the analysis of the incremental impact of the proposed rule.

From 2003 to 2015, there were approximately 1,200 incidents on gas transmission pipelines from all causes, one-third of which were from causes detectable by modern integrity assessment methods. **Table ES-1** summarizes monetized consequences from these incidents, including the estimated monetary value of fatalities and injuries ("value of a statistical life"), property damage, and other costs. Table ES-1 also shows monetized consequences from corrosion and excavation damage incidents in certain locations; these incidents may be similar to damages from Type A, Area 2 gas gathering lines proposed to be regulated.

Table ES-1. Historical Consequences of Onshore Gas Transmission Incidents (2003-2015; Millions 2015$)

Category	Death[1]	Serious Injury[2]	Other Costs of Incident[3]	Evacuation[4]	Total
All causes	$216.2	$125.3	$678.6	$21.1	1,041.3
Causes detectable by integrity assessment	$84.6	$59.2	$593.2	$5.6	$683.4
Corrosion and excavation damage[5]	$84.6	$19.7	$56.1	$5.6	$166.1

Source: Based on PHMSA Incident Report data
1. Value based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Value based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Includes all costs reported by the operator including estimated cost of public and non-operator private property damage. Excludes operator property damage and repair costs which may result in underestimating avoided consequences.
4. Value based on estimated $1,500 per person evacuation cost.
5. Reflects Class 1 and Class 2 locations.

In addition, between 2010 and 2014, gas transmission incidents resulted in an average release of 20,489 thousand cubic feet of natural gas. Natural gas primarily comprises methane, a greenhouse gas (GHG).

ES.3 ASSESSMENT OF REGULATORY IMPACT

Operators report gas transmission pipeline mileage and characteristics annually, and information on incidents involving the pipe that meet certain characteristics. PHMSA used these publically available data to estimate affected mileage subject to the proposed rule. Only a small portion of gas gathering pipelines are currently subject to reporting. Thus, much less data is available on this sector.

Relative to the baseline for the analysis, the proposed requirements in Topic Area 1 will result in integrity verification of previously untested pipe and pipe for which operator records are inadequate, and assessments similar to current requirements for HCA pipe for some pipe in moderate consequence areas (MCAs). Operators will comply through a combination of pressure testing, inline inspection (ILI), including upgrades to accommodate ILI, and direct assessment of approximately 16,600 miles of onshore gas transmission pipeline (**Table ES-2**). The affected mileage represents approximately five percent of total onshore gas transmission mileage. The proposal also provides an alternative to current requirements in cases of inadequate records that does not involve cut out and replacement of pipe.

Table ES-2. Summary of Estimated Mileage Impacted by Proposed Integrity Verification and Assessment Requirements, Topic Area 1	
Category	**Miles**
Re-establish MAOP: HCA > 30% SMYS	909
Re-establish MAOP: inadequate records	4,363
Integrity Assessment: MCA	7,379
Re-establish MAOP: HCA 20-30% SMYS; non-HCA Class 3 and 4; MCA Class 1 and 2	2,817
Total	**15,468**

HCA = high consequence area
MAOP = maximum allowable operating pressure
MCA = moderate consequence area
SMYS = specified minimum yield strength
Source: Analysis of PHMSA 2014 Annual Report data, pipeline and roadway maps, and PHMSA's best professional judgment as detailed in body of this report

Topic Areas 2 through 7 also apply to gas transmission pipeline and include process modifications and clarifications, more timely repair of defects, corrosion control, inspections, and other safety provisions, some of which operators already implement. **Table ES-3** summarizes the estimated affected mileages.

Table ES-3. Summary of Estimated Impact, Topic Areas 2 through 7		
Topic Area	**Topic Area Description**	**Estimated Impact**
2	More timely repairs	2,407 HCA miles[1]
3	Management of change	70 operators[2]
4	Corrosion control	See note 3
5	Inspection following extreme events	1,017 operators[4]
6	MAOP records	1,440 reports and 10-20 annually[5]
7	Launcher/receiver pressure relief	10 launchers/receivers

HCA = high consequence area
MAOP = maximum allowable operating pressure
NA = not applicable (no impact due to current compliance)
1. Average assessed per year. Represents mileage not included under Topic Area 1.
2. Based on best professional judgment.
3. Small portion of mileage estimated to be out of compliance for various requirements; interference surveys estimated to be needed for 2,711 miles.
4. Source: 2014 Gas Transmission Annual Reports
5. Based on a prestatutory baseline; operators are in compliance with the initial requirement.

Topic Area 8 will result in reporting on an estimated 344,000 miles of currently unregulated gas gathering pipeline infrastructure, and operators of an estimated 69,000 of these miles will also have to implement corrosion control and other safety measures (**Table ES-4**).

Table ES-4. Summary of Estimated Impact, Topic Area 8	
Proposed Requirements	**Estimated Mileage**
Corrosion control and safety measures: unregulated gas gathering lines >8" in diameter and operating in Class 1 at >20% specified minimum yield strength	68,749
Reporting: unregulated gas gathering lines	344,086

Table ES-4. Summary of Estimated Impact, Topic Area 8	
Proposed Requirements	**Estimated Mileage**
Source: Based on estimate from Amy Emmert, Policy Advisor, Upstream and Industry Operations, American Petroleum Institute, Re: Pipeline Safety: Safety of Gas Transmission Pipelines (Docket No. PHMSA-2011-0023), October 23, 2012, representing data from 45 operators, and assuming these operators represent 70% of the total, based on PHMSA best professional judgment.	

These actions will reduce the risk of gas transmission and gathering pipeline incidents, resulting in avoided property damage, death and injury, emergency responses and evacuations (see Table ES-3), and greenhouse gas emissions.

ES.4 ESTIMATION OF COSTS AND BENEFITS

Incremental costs of the proposed rule include costs associated with integrity assessments (pressure testing, inline inspection, upgrading to accommodate inline inspection, and direct assessment); GHG emissions associated with those assessments; corrosion control monitoring and surveys; process and program development; and reporting on previously unreported pipelines. PHMSA used per mile unit cost estimates for the assessment and testing components, and applied the costs using annual report data on pipeline characteristics and historical assessment methods. PHMSA estimated costs of lost gas by calculating lost volume and using the current gas price and the climate change effects by multiplying the volume by estimates of the social cost of methane (SCM). PHMSA estimated programmatic and reporting costs based on labor hours and labor costs.

To estimate the reductions in risks from implementing the safety provisions, PHMSA estimated defect discovery rates and the percent that would otherwise result in an incident (Topic Area 1). PHMSA also matched resulting incident rates to those from pipeline infrastructure currently subject to similar requirements to the extent feasible (Topic Area 8). For the remaining topic areas, PHMSA used best professional judgment for illustration or performed a break-even analysis.[1] **Table ES-5** summarizes the estimates of incidents averted by Topic Area.

Table ES-5. Summary of Estimated Incidents Averted[1]

Estimate	Topic Area						
	1	3	4	5	7	8	Total
Annual	5-15	1	7	1	0	19	33-43
Total (15 years)	74-221	15	108	8	1	271	477-624

Note: detail may not add to total due to independent rounding.
n.e. = not estimated
1. Topic Areas 2 and 6 not estimated.

For example, during 2003–2015, an average of 31 assessment-preventable incidents occurred each year on all onshore gas transmission pipeline mileage (range is 26 – 44). As shown in Table ES-5, the analysis of benefits of proposed requirements in Topic Area 1, which addresses assessment-preventable incidents on the estimated mileage shown in Table

[1] In many cases throughout this RIA, PHMSA lacked direct data or evidence on the values of parameters used in the analysis. In these cases, PHMSA relied on its experts' best professional judgment of the likely values. We seek comment, especially supported by accompanying data, on the accuracy of this judgment.

ES-2, is based on an estimate of averting 5 to15 such incidents annually. Absent adoption of the proposed rule, the number of incidents could exceed past numbers due to factors such as aging pipeline; however, such projections are speculative.

To value these avoided incidents, PHMSA used average consequences of incidents in similarly located pipelines based on the affected mileage which varies by Topic Area (i.e., avoided costs. PHMSA updated property damages to current dollars and used standard departmental methods for monetizing avoided injuries and fatalities based on the value of a statistical life. PHMSA valued evacuations by multiplying the number of persons evacuated by an estimate of per person evacuation cost (approximately $1,500).

To estimate the costs of GHG emissions associated with avoided incidents, PHMSA used data on releases per incident and estimates of the SCM as well as the social cost of carbon (SCC; due to combustion of gas).

ES.5 COSTS AND BENEFITS OF THE PROPOSED RULE

Table ES-6 summarizes the average annual present value benefits and costs using 7% and 3% discount rates, respectively. Topic Area 1 accounts for the majority of the benefits and costs. The majority of Topic Area 1 benefits reflect cost savings from material verification (processes to determine MAOP for segments for which records are inadequate) under the proposed rule compared to existing regulations; the range in these benefits reflects different effectiveness assumptions for estimating safety benefits. Costs reflect primarily integrity verification and assessment costs (pressure tests, inline inspection, and direct assessments). The proposed gas gathering regulations under Topic Area 8 account for the next largest portion of benefits and costs. Costs and benefits under Topic Area 8 primarily reflect safety provisions and associated risk reductions on previously unregulated lines.

Table ES-6. Summary of Present Value Average Annual Benefits and Costs[1] (Millions; 2015$)

Topic Area	7% Discount Rate		3% Discount Rate	
	Benefits	Costs	Benefits	Costs
1	$196.9 -$230.5	$17.8	$247.8 -$288.6	$22.0
2	n.e.[2]	$2.2	n.e.[2]	$1.3
3	$1.1	$0.7	$1.2	$0.8
4	$5.5	$6.3	$5.9	$7.9
5	$0.3	$0.1	$0.3	$0.1
6	n.e.	$0.2	n.e.	$0.2
7	$0.4	$0.0	$0.6	$0.0
8	$11.3	$12.6	$14.2	$15.1
Total	**$215.6 -$249.2**	**$39.8**	**$270.0 -$310.8**	**$47.4**

n.e. = not estimated
1. Total present value over 15-year study period divided by 15. Additional costs to states estimated not to exceed $1.5 million per year. Range of benefits reflects range in estimated defect failure rates.
2. Break even value of benefits, based on the average consequences for incidents in high consequence areas, would equate to approximately one incident averted over the 15-year study period.

Table ES-7 summarizes costs and benefits by subtopic within Topic Area 1.

Table ES-7. Summary of Average Annual Present Value Benefits and Costs for Topic Area 1 (Millions 2015$)[1]				
Subtopic	**Average Annual Benefits (7%)**	**Average Annual Costs (7%)**	**Average Annual Benefits (3%)**	**Average Annual Costs (3%)**
MAOP verification for segments within HCA	$3.6 -$8.9	$0.5	$4.5 -$11.1	$0.6
MAOP verification for segments with inadequate records within HCA and Class 3 and Class 4	$188 -$204.7	$8.0	$237 -$257.7	$9.8
Integrity assessments for segments within MCA in Class 3 and Class 4, and Class 1 and Class 2 (piggable)	$3 -$9.6	$6.3	$3.4 -$11	$7.9
MAOP verification for segments within HCA(20%-30% SMYS) and MCA (Class 3 and Class 4, and Class 1 and Class 2 piggable)	$2.4 -$7.3	$3.0	$2.9 -$8.9	$3.6
Total	**$196.9 -$230.5**	**$17.8**	**$247.8 -$288.6**	**$22.0**

HCA = high consequence area
MAOP = maximum allowable operating pressure
MCA = moderate consequence area
SMYS = specified minimum yield strength
1. Total present value over 15-year study period divided by 15.

Tables ES-8 and **ES-9** show the breakdown of benefits for each topic area by category at 7% and 3% discount rates, respectively.

ES-8. Summary of Average Annual Present Value Benefits, 7% Discount Rate (Millions 2015$)[1]				
Topic Area	**Safety**	**Cost Savings[2]**	**Climate[3]**	**Total**
1	$16.4 -$44.5[4]	$177.8	$2.7 -$8.2	$196.9 -$230.5
2	n.e.	n.e.	n.e.	n.e.
3	$0.5	$0.0	$0.6	$1.1
4	$1.6	$0.0	$4.0	$5.5
5	$0.0	$0.0	$0.3	$0.3
6	n.e.	n.e.	n.e.	n.e.
7	$0.4	$0.0	$0.0	$0.4
8	$9.7	$0.0	$1.6	$11.3
Total	**$28.6 -$56.7**	**$177.8**	**$9.2 -$14.62**	**$215.6 -$249.2**

n.e. = not estimated
1. Total present value over 15-year study period divided by 15.
2. Material verification cost savings would provide comparable safety with a pressure test at or above 1.25 times maximum allowable operating pressure and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods.
3. Using 3% discounted values. TA 1 includes range for uncertainty.
4. Range reflects uncertainty in incidents averted rates.

Table ES-9. Summary of Average Annual Present Value Benefits, 3% Discount Rate (Millions 2015$)				
Topic Area	Safety	Cost Savings[1]	Climate[2]	Total
1	\$20.6 -\$56.1[3]	\$224.4	\$2.7 -\$8.2	\$247.8 -\$288.6
2	n.e.	n.e.	n.e.	n.e.
3	\$0.7	\$0.0	\$0.6	\$1.2
4	\$2.0	\$0.0	\$4.0	\$5.9
5	\$0.0	\$0.0	\$0.3	\$0.3
6	n.e.	n.e.	n.e.	n.e.
7	\$0.5	\$0.0	\$0.0	\$0.6
8	\$12.5	\$0.0	\$1.6	\$14.2
Total	**\$36.4 -\$71.8**	**\$224.4**	**\$9.2 -\$14.62**	**\$270.0 -\$310.8**

n.e. = not estimated
1. Material verification cost savings would provide comparable safety with a pressure test at or above 1.25 times maximum allowable operating pressure and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods.
2. Using 3% discounted values. TA 1 includes range for uncertainty in incidents averted rates.
3. Range reflects uncertainty in incidents averted rates.

For the seven percent discount rate scenario, approximately 13 to 23 percent of benefits are due to safety benefits from incidents averted, 71 to 82 percent represent cost savings from MAOP verification in Topic Area 1, and 4 to 6 percent are attributable to reductions in GHG emissions. PHMSA estimated a net annual reduction of 931 metric tons of carbon dioxide and 4,600 metric tons of methane, a powerful greenhouse gas (**Table ES-10**).

ES-10. Net Average Annual Reduction in Greenhouse Gas Emissions[1]				
	Low Estimate		High Estimate	
Change in Emissions	MT CH_4[2]	MT $C0_2$	MT CH_4[2]	MT $C0_2$
Averted due to reduced incidents	5,864	968	9,332	1,501
Increased from compliance actions	-1,228	-44	-1,228	-44
Net reduction	4,636	924	8,104	1,457

MT= Metric ton
CH4= Methane, the primary component of natural gas
C02= Carbon Dioxide, marginal component of natural gas and product of methane combustion
1. Range reflects uncertainty in assessment effectiveness.
2. Converted based on one thousand cubic feet of methane = 0.0189 MT.

Based on estimated costs to states not exceeding \$1.5 million per year, PHMSA determined that the rule would not impose annual expenditures by states in excess of the criteria in the Unfunded Mandates Reform Act. An Initial Regulatory Flexibility Analysis is in the docket for the rulemaking discusses small entity concerns.

ES.6 LIMITATIONS AND UNCERTAINTIES

There is substantial uncertainty in several parameters underlying the analysis including affected mileage, unit costs, effectiveness, and value of avoiding incidents. With respect to the affected mileage, commitments to expand assessment and repair programs beyond HCAs have already been made by the industry in PHMSA's workshops and in response to the ANPRM dated August 25, 2011 (76 FR 53086). These commitments have the effect of reducing the compliance costs and the benefits associated with the proposed rule.

Also, in estimating costs and avoided risks of incidents, PHMSA relied on existing experience which reflects primarily assessment in HCAs. Extrapolation of this experience could overstate costs in MCAs due to the lower density of development. There is also uncertainty regarding the effectiveness of the proposal to reduce the risks of incidents. This is in part due to uncertainty in the estimates of defect discovery rates and the estimated percentages of defects that would result in an incident. In addition, there is no data on the extent of mileage that would meet the definition of an MCA.

Costs could also increase or decrease over time due to a variety of factors including technological improvement, changes in industry structure, and changes in prices. In particular, PHMSA expects ongoing development of new inline integrity assessment technologies to reduce the cost of ILI and to allow line segments that are currently unpiggable using conventional technology to use ILI without significant upgrade or replacement of the segment. A reduction in these assessment costs over time would further increase the net benefit of the proposed rule.

The benefits of reducing risks represent consequences from incidents reported by pipeline operators which do not include all consequences associated with incidents. Operators submit their casualty and direct loss/damage estimates only which may undervalue the impact of all consequences since other consequential costs, including indirect costs, to operators, other stakeholders, or society are not included. The inclusion of these unreported consequential costs of incidents would increase the estimated safety benefits associated with the proposed rule. The averages of reported consequences of past incidents could under- or overstate future consequences.

ES.7 ALTERNATIVES EVALUATED

PHMSA also evaluated a number of alternatives to the proposed rule. **Table ES-11** summarizes provides a summary of this analysis.

Table ES-11. Summary of Alternatives Analysis

Topic Area	Alternative
1	More stringent MCA criteria (1 building in PIR) and expansion of testing to re-establish MAOP
1	More limited MCA scope (excluding less than 8” diameter pipe)
1	Expand scope of HCA instead of defining MCA
1	Increase applicability of proposed requirements to all pipe outside of HCAs
1	Shorter compliance deadline (10 years) and shorter reassessment interval (15 years) for MCA assessments
1	Require pressure testing to verify MAOP for HCAs and Class 3 and 4 locations
1	No action[1]
3	Extend compliance deadlines
4	Checking under pipe supports; premium quality backfill; additional corrosion protection coating; additional gas stream processing/cleaning
5	Extend compliance deadlines
7	No action
7	Extend compliance deadlines

Table ES-11. Summary of Alternatives Analysis

Topic Area	Alternative
HCA = high consequence area MCA = moderate consequence area MAOP = maximum allowable operating pressure PIR = potential impact radius	

The alternatives analysis is subject to the same limitations and uncertainties associated with the analysis of the proposed rule.

Table of Contents

1. INTRODUCTION

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is proposing changes to the Federal pipeline safety regulations in 49 CFR Parts 191 and 192, which cover the transportation of gas by transmission and gathering pipelines. Specifically, PHMSA is proposing to issue new regulations or revise existing regulations in the following topic areas:

1. Integrity Assessment and Remediation for Segments Outside High Consequence Areas (HCAs) and to re-establish Maximum Allowable Operating Pressure (MAOP)
2. Integrity Management Program Process Clarifications
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4. Corrosion Control
5. Inspection of Pipelines Following Extreme Events
6. MAOP Exceedance Reports and Records Verification
7. Launcher/Receiver Pressure Relief
8. Gas Gathering Pipeline Safety

This report provides analysis of the benefits and costs of the proposed regulatory changes by topic area.

1.1 BACKGROUND

This section provides background on the regulated industry.

Overview of Gas Transportation Pipeline Systems

In accordance with 49 CFR §192.3, "transportation of gas"[2] means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce." This definition applies to the transportation of flammable, toxic, or corrosive gases, including gases other than natural gas,[3] such as propane, hydrogen, and synthetic gas when transported via pipeline in gaseous phase. However, for simplicity, only natural gas is referred to in the following discussion, since natural gas is by far the predominant commodity shipped by pipeline in the gaseous phase, representing 95% of the onshore mileage regulated by PHMSA.

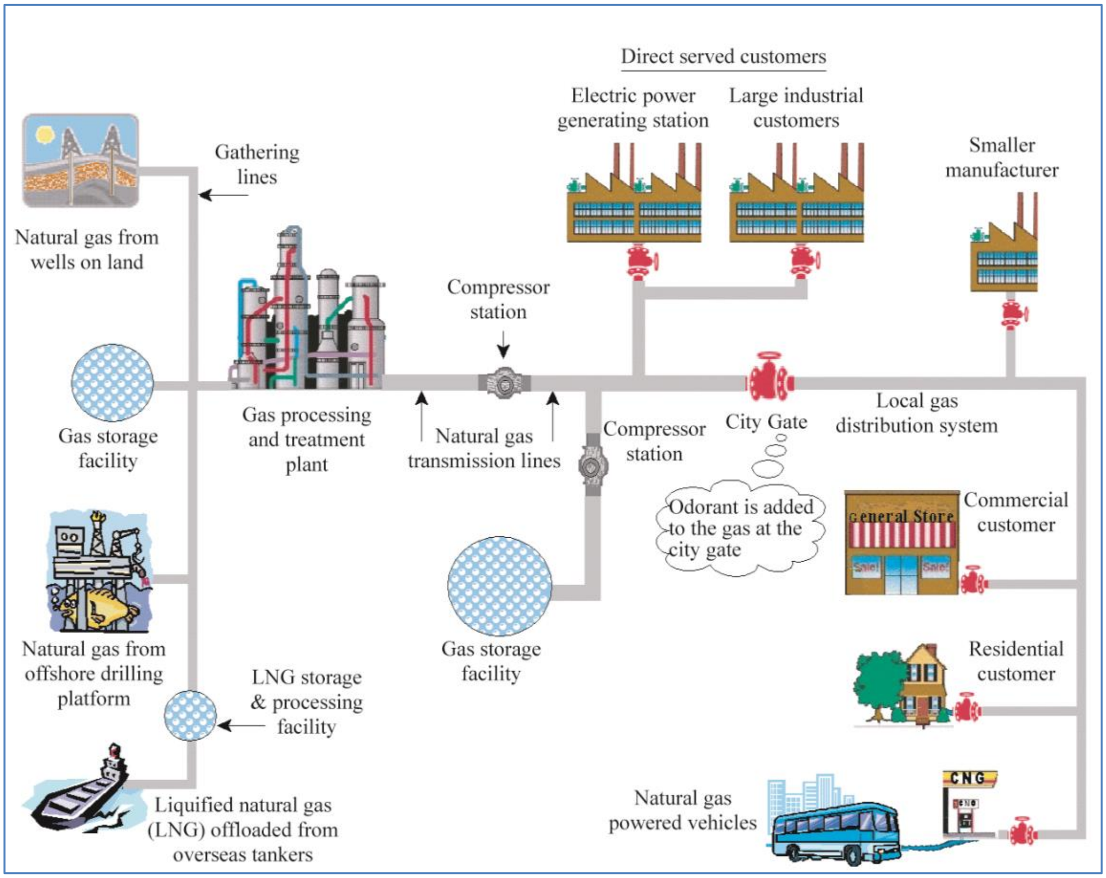
Natural Gas Pipeline Systems

The natural gas infrastructure is composed of thousands of miles of pipelines, as well as processing facilities, and related components such as valves, controllers, and other such appurtenances. However, to envision the general overall pipeline infrastructure it is best to consider it in three different parts connected together to transport natural gas from the production field, where gas is extracted from underground, to the end user, where the gas is used as an energy fuel or as a raw material for production. These three parts are known as

[2] *Gas* means natural gas, flammable gas, or gas which is toxic or corrosive. 49 CFR §192.3

[3] Natural gas is a naturally occurring hydrocarbon gas mixture consisting primarily of methane.

gathering systems, transmission systems, and distribution systems. Each type of gas pipeline system can be seen to serve a particular purpose. The graphic below illustrates the overall pipeline infrastructure.



Gathering Pipeline Systems

As currently defined by Federal pipeline safety regulations (49 CFR 192.3), a gathering pipeline system "transports gas from a production facility to a transmission line or main." Before 2006, onshore gas gathering lines were exempt from regulation if they were outside the limits of any incorporated or unincorporated city, town, or village or outside any designated residential or commercial area such as a subdivision, business or shopping center, or community development. As a result, some gas gathering lines that pass close to areas where people work or live were not being regulated, simply because they were in "rural" areas; whereas, some portions where an incident would likely not affect people were regulated only because they were located in the city limits. To address these issues, and in response to a Congressional mandate, PHMSA revised its regulations in 2006 to more clearly define which portions of the natural gas pipeline network are "gathering" pipelines and which portions are regulated.

To determine if a gathering pipeline is a regulated line, an operator must use criteria in API RP 80,[4] subject to limitations listed in 49 CFR 192.8, to determine if a pipeline incident

[4] American Petroleum Institute (API) Recommended Practice (RP) 80, which is incorporated by reference into the Federal pipeline safety regulations (49 CFR 192.7).

could impact people by being close enough to a number of homes or to areas/buildings where people congregate.[5] Offshore gas gathering pipelines and high-pressure onshore lines meeting the criteria must meet requirements of 49 CFR Part 192 applicable to gas transmission pipelines. Onshore gas gathering pipelines that operate at lower pressures must comply with a subset of these requirements specified in §192.9.

Historically, gathering lines typically operated at relatively low pressures and flow rates, and had smaller diameters than transmission lines. However, with the recent significant expansion of high volume, high pressure natural gas production from unconventional geological formations, more gathering pipeline systems are being constructed and operated using parameters similar to transmission pipelines.

Transmission Pipeline Systems

Transmission pipelines are used to transport natural gas from gathering systems to processing and storage facilities. Along the way, gas may be extracted from the transmission pipelines into gas distribution systems or to directly serve industrial and agricultural customers. As defined in 49 CFR §192.3, "transmission line" means a pipeline, other than a gathering line, that: (1) transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress[6] of 20% or more of SMYS;[7] or (3) transports gas within a storage field.

Transmission pipeline systems include all of the equipment and facilities necessary to transport natural gas. This includes the pipe, valves, compressors, processing and storage facilities, and other equipment and facilities. Transmission pipelines are constructed from steel pipe and can range in size from several inches to several feet in diameter. They can be designed to operate from relatively low pressures to over 1000 pounds per square inch (psi) and can range in length from hundreds of feet to hundreds of miles. They can be intrastate, operating within the geographical boundaries of a single State, or interstate, operating across one or more State lines.

Most transmission pipelines are operated remotely from centrally-located control centers. These control centers allow for the efficient operation of either a single pipeline, or a number of different pipeline systems from a single location. From a single pipeline control center operators can start and stop compressors, open and close valves, monitor product movement, monitor leak detection systems, conduct training operations, and perform other system management tasks. Actions can be taken in response to field data transmitted from remote locations. Often, data observed at a central control center is confirmed by field personnel at affected locations before actions are taken.

Natural Gas Distribution Pipeline Systems

Most natural gas distribution systems are high-pressure distribution systems in that the gas

[5] The criteria for regulating gathering lines are described in more detail on Table 3.8-1, p. 108.

[6] *Hoop stress* is stress (force) exerted in a circumferential direction (perpendicular both to the axis and to the radius of the pipe) at a point in the pipe wall as a result of the pressure of the gas being transported.

[7] *SMYS* is the specified minimum yield strength for steel pipe manufactured in accordance with a listed specification. A common term used for steel pipe under PHMSA jurisdiction, SMYS provides an indication of the minimum stress the pipe may experience that will cause plastic (permanent) deformation of the pipe. SMYS is used to establish the MAOP of the pipe.

pressure in the "main" is higher than the pressure provided to the customer. A main in a distribution system serves as a common source of supply for multiple "service lines." A service line is a distribution system line that transports the gas from a common source of supply (i.e., a main) to one or more individual residential or small commercial customers, through a meter header or manifold. A customer meter is used to measure the volume of gas transferred from an operator to a consumer. A service line (and PHMSA jurisdiction) ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

Distribution system pipelines are generally smaller in diameter than gas transmission pipelines and operate at reduced pressures. Typically, gas is delivered to residential customers at pressures lower than the operating pressure of the mains, so a service regulator is used to limit the pressure of gas delivered to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.

Many gas distribution pipelines are made of plastic pipe rather than steel. Some antiquated systems still in operation are made from cast iron or ductile iron; however, these pipes are prone to corrosion and are being replaced. Distribution system mains are normally installed underground, along or under streets and roadways. Service lines connected to mains are also installed underground but their routing is less uniform.

Local distribution companies (LDCs) own and operate natural gas distribution pipelines. In some cases a municipal government may act as the LDC to operate the gas distribution system. LDCs receive natural gas from transmission pipelines and distribute it to commercial and residential end-users. The point at which the local distribution system connects to the natural gas transmission pipeline is known as the city gate. At the city gate the gas pressure is lowered and a sour-smelling odorant is added to the gas to help users detect even small quantities of leaking gas.

Pipeline Regulation

The Federal Energy Regulatory Commission (FERC)[8] is responsible for economic regulation of the transmission and sale of natural gas for resale in interstate commerce. The main objectives of economic regulation to ensure open access, non-discriminatory pricing, and protect shippers from the exercise of market power. FERC also approves the siting and abandonment of interstate natural gas facilities, including pipelines, storage facilities, and liquefied natural gas (LNG) facilities. FERC also ensures the safe operation and reliability of proposed and operating LNG terminals. However, FERC does not regulate or provide oversight for gas pipeline safety, nor does it regulate pipeline transportation on or across the Outer Continental Shelf. FERC does not regulate intrastate gas transmission, gathering lines, or local distribution systems; economic regulation of such systems is typically the responsibility of state regulatory commissions.

Pipeline operators are also regulated by EPA for air and water emissions under the Clean Air and Clean Water Acts, and for employee safety by the Occupational Safety and Health Administration.

PHMSA and its state partners regulate pipeline safety for jurisdictional gas gathering, transmission, and gas distribution systems, under minimum Federal safety standards

[8] See more information on FERC regulatory responsibilities for gas pipelines and facilities at www.ferc.gov.

authorized by statute[9] and codified by regulations in 49 CFR Part 192.[10] Generally, PHMSA regulates interstate pipelines directly, and delegates regulation of intrastate pipeline systems, including gathering lines and local distribution systems, to state agencies.

Federal regulation of gas pipeline safety began in 1968 with the issuance of interim minimum Federal safety standards for gas pipeline facilities and the transportation of natural and other gas, in accordance with the Natural Gas Pipeline Safety Act of 1968 (Public Law 90-481). The Interim Minimum Federal Standards basically adopted by reference existing state and industry standards and acknowledged that establishing an entirely new set of safety standards as required in the 1968 Act would take at least two years. The 1968 Act also provided that "Such standards may apply to the design, installation, inspection, testing, construction, extension, operations, replacement, and maintenance of pipeline facilities."

In 1970, DOT issued minimum safety standards to address multiple, various, and specific aspects of gas pipeline transportation. These included definitions and minimum requirements related to: gas pipeline construction; customer meters, service regulators and service lines; class locations; testing and uprating; and, pipeline materials, system components and facilities design.

In 1971, DOT began issuing minimum safety standards to address specific aspects of gas pipeline design, installation, inspection, testing, construction, operations, replacement, and maintenance. These standards began addressing aspects such as: corrosion control; confirmation of MAOP; repair sleeves; modification of pressure relief devices; qualification of pipe; gas odorization; welding; use of plastic pipe, caulked bell and spigot joints; and line markers. Experienced-based regulations continue to be issued today, and are often based upon issues, lessons learned, or needs identified through the investigation of individual gas pipeline incidents, and, in more recent years, knowledge gained through aggregate experience and data trends.

In some cases, although new safety standards have been established through regulations, related pipeline conditions may be exempted. For example, 49 CFR 192.619 establishes restrictions on operating a pipe segment in excess of the MAOP determined in accordance with that section. However, as noted in § 192.619(c), the requirements on pressure restrictions do not always apply: an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding dates specified in the regulation for the type of pipeline being considered. Those specified dates are usually prior to 1970, when relevant regulations were first written. In those cases, the operator is not currently required to pressure test the pipeline or otherwise verify the integrity of the pipeline to operate at pressure up to the MAOP.

Similarly, buried or submerged pipe installed after July 31, 1971 must be protected against external corrosion through the use of external protective coating and, with noted exceptions, a cathodic protection system.[11] Pipe installed before then is not required to have protective

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[9] Title 49, United States Code, Subtitle VIII, Pipelines, Sections 60101, *et. seq.*

[10] Information is available on pipeline regulatory authorities at http://primis.phmsa.dot.gov/comm/Partnership.htm.

[11] A buried pipeline can act as an anode on a natural battery, leading to a flow of iron ions away from the pipeline and into the ground. Over time, this flow manifests itself as metal loss/corrosion of the pipeline. A cathodic protection system typically uses an electricity source to generate a counter flow current to an external anode, causing

coating and must have cathodic protection only in areas where active corrosion is found.

One specific issue with pipe manufactured before the 1970's is that some manufacturing techniques are prone to contain latent defects as a result of the manufacturing process. Line pipe manufactured using low frequency electric resistance welding (LF-ERW), lap welded pipe, or pipe with seam factor less than 1.0, is susceptible to failure of the longitudinal seam. These manufacturing techniques were widely used before regulations were promulgated in 1970, and many of those pipes are exempt from certain regulations, notably the requirement to pressure test the pipeline to establish MAOP. A substantial amount of LF-ERW pipeline is still in service.

"Pipeline integrity" means that the pipeline is of sound and unimpaired condition and can safely carry out its function under the conditions and parameters in which it operates. "Integrity management" encompasses the many activities pipeline operators must undertake to ensure the integrity of their pipelines. Integrity management regulations were promulgated in 2004 for gas transmission pipelines.

The institution of regulatory requirements for integrity management followed the gas transmission pipeline incident that killed 12 people near Carlsbad, New Mexico, on August 19, 2000. The pipeline was owned and operated by El Paso Natural Gas. Investigation into the failed pipe determined that the cause was severe internal corrosion resulting in a reduction in pipe wall thickness of over 70%. The integrity management process requires that operators perform a risk analysis, identify threats, periodically conduct integrity assessments, repair defects found, and implement additional preventive and mitigation measures to assure pipeline integrity for selected pipe segments located in defined High Consequence Areas. The process is intended to assure that case-specific threats and integrity issues, such as described above, are managed to prevent failures and assure pipeline integrity. Integrity management requirements for gas distribution pipeline systems were promulgated in 2009. PHMSA and State inspectors review operators' written IM programs and associated records to verify that the operators have used all available information about their pipelines to assess risks and take appropriate actions to mitigate those risks.

However, infrequent severe incidents indicate that some pipelines continue to be vulnerable to legacy issues, such as LF-ERW pipe. Also, some severe pipeline incidents have occurred in areas outside HCAs where the application of integrity management principles is not required. Data shows that gas pipelines continue to experience significant incidents and that some historical failure causes (such as corrosion) have still not been effectively addressed, and mitigative measures (such as rupture detection and response) have not been entirely effective in preventing or mitigating the impacts of gas pipeline incidents. Organizations such as the General Accounting Office (GAO) and the National Transportation Safety Board (NTSB) have made numerous recommendations for improving gas safety regulations. Congress has mandated that PHMSA address certain issues through specific legislation. The proposed rule is intended to address some of those recommendations and legislative requirements.

On August 25, 2011, PHMSA published an Advance Notice of Proposed Rulemaking

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the pipeline to become a cathode, and hence to cease losing iron ions.

(ANPRM) seeking public comment on the following topics[12]:

A. Modifying the definition of HCAs
B. Strengthening requirements to implement preventive and mitigative (P&M) measures for pipeline segments in HCAs
C. Modifying repair criteria
D. Improving requirements for collecting, validating, and integrating pipeline data
E. Making requirements related to the nature and application of risk models more prescriptive
F. Strengthening requirements for applying knowledge gained through the Integrity Management Program (IMP)
G. Strengthening requirements on the selection and use of assessment methods
H. Valve spacing and the need for remotely or automatically controlled valves
I. Corrosion control
J. Pipe manufactured using longitudinal weld seams
K. Establishing requirements applicable to underground gas storage
L. Management of change
M. Quality management systems (QMS)
N. Exempting facilities installed prior to the regulations
O. Modifying the regulation of gas gathering lines

PHMSA received 103 comment letters in response to the ANPRM. Comments submitted to the docket were received from the pipeline industry, government agencies, pipeline trade associations, citizen groups, private citizens, consultants, municipalities, and trade unions. PHMSA's responses to these comments are included in the accompanying NPRM.

On August 30, 2011, after the ANPRM was issued, the NTSB adopted (as final) its report on the San Bruno, California gas transmission pipeline incident that occurred on September 9, 2010. In its report, the NTSB issued safety recommendations P-11-1 and P-11-2 and P-11-8 through -20 to PHMSA, P-10-2 through -4 and P-11-24 through -31 to the pipeline operator, Pacific Gas & Electric (PG&E), and P-10-4 through -6 and P-11-22 and -23 to the California Public Utilities Commission (CPUC), among others. PHMSA considered several of these NTSB recommendations directly related to the topics addressed in the ANPRM and in developing this proposed rule.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act) was signed into law on January 3, 2012, also after the ANPRM was issued. Several of the Act's statutory requirements address the topics considered in the ANPRM and have had a

[12] 76 FR 53086 Pipeline and Hazardous Materials Safety Administration, Pipeline Safety, 49 CFR Part 192, [Docket No. PHMSA–2011–0023] ANPRM. The ANPRM may be viewed at http://www.regulations.gov.

substantial impact on PHMSA's approach to this proposed rulemaking.

The Notice of Proposed Rulemaking (NPRM) addresses additional topics that have arisen since issuance of the ANPRM, including NTSB Recommendation P-14-1, issued in response to a gas transmission pipeline incident on December 11, 2012 in Sissonville, West Virginia, and the August 2014 Government Accountability Office Report GAO-14-667.[13] GAO reviewed oil and gas transportation infrastructure issues and recommended that DOT move forward with proposed rulemaking to address safety risks, including emergency response planning from newer gathering pipelines.

1.2 PROPOSED RULE

Based on the ANPRM, comments received, and the subsequent activities as described above, PHMSA is proposing to make the following changes to the Federal pipeline safety regulations set forth in 49 CFR Parts 191 and 192.

1. Re-establish MAOP, Verification of Material Properties, and Integrity Assessment and Remediation for Segments Outside HCAs
    a. In accordance with the Congressional Mandate, require that pipeline operators conduct special integrity assessments, such as pressure tests or inline inspections (ILI) in conjunction with engineering critical assessments, to re-establish MAOP for selected pipeline segments that were previously exempted from testing under a grandfather clause, if they operate at pressures that exceed 30% of SMYS and are located in a HCA.
    b. In accordance with the Congressional Mandate, require that pipeline operators re-verify material properties and conduct special integrity assessments, such as pressure tests or ILI in conjunction with engineering critical assessments, to re-establish MAOP for selected pipeline segments that that do not have adequate records to establish MAOP if they are located in a HCA or a Class 3 or 4 location.
    c. Require initial and periodic integrity assessments and remediation for non-HCA pipelines in newly-defined moderate consequence areas (MCAs). Data analysis requirements, assessment methods, and repair criteria for immediate conditions would be the same as for HCAs. Repair criteria for two-year conditions in MCAs would be the same as the current one-year conditions for HCAs. Assessments conducted to re-establish MAOP would count as an initial assessment or re-assessment, as applicable, under the proposed non-HCA assessment rule or 49 CFR Part 192, Subpart O (HCAs).
    d. To address NTSB Recommendation P-11-14, require that pipeline operators conduct special integrity assessments, such as pressure tests or ILI in conjunction with engineering critical assessments, to re-establish MAOP for selected pipeline segments that were previously exempted from testing under a grandfather clause, (i) if they operate at pressures less than or equal to 30% of SMYS and are located in a HCA, or (ii) if the pipeline segment operates at

[13] Government Accountability Office (GAO) Report to Congressional Requestors, *Department of Transportation Is Taking Actions to Address Rail Safety, but Additional Actions Are Needed to Improve Pipeline Safety*, Report No. GAO-14-667, August 2014. http://www.gao.gov/products/GAO-14-667

pressures greater than or equal to 20% of SMYS that is located in a Class 3 or 4 location, or in a piggable pipeline located in a newly defined MCA in a Class 1 or 2 location.

2. IMP Process Clarifications
    a. Clarify IMP process requirements in the following areas: management of change; threat identification; risk assessments; baseline assessment methods; preventive and mitigative measures; periodic evaluations and assessments; and, notifications for reassessment interval extensions.
    b. Clarify (and, in limited cases, revise) repair criteria for remediating defects discovered in HCA segments.
    c. Require notification to PHMSA if the operator cannot obtain sufficient information to determine if a condition presents a potential threat to the integrity of the pipeline within 180 days of completing an assessment.
3. Management of Change – Require gas transmission pipeline operators to evaluate and mitigate risks as necessary, during all phases of the useful life of a pipeline, including management of change. Each operator would have to develop and follow a management of change process that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary.
4. Corrosion Control – Expand corrosion control requirements in the following areas: pipe coating assessments; remedial actions for external corrosion mitigation deficiencies; close interval surveys; interference current remedial actions; gas stream monitoring program; and preventive and mitigative measures for internal and external corrosion control.
5. Inspection of Pipelines Following Extreme Events – Require inspections of pipelines in areas affected by extreme weather, man-made and natural disasters, and other similar events. Such inspections would ensure that pipelines are still capable of being safely operated after these events and would identify the mitigative and corrective actions that might be required to ensure safe operation.
6. MAOP Exceedance Reports and Records Verification – Require reporting of MAOP exceedances, development of operation and maintenance procedures to assure MAOP is not exceeded by the amount needed for overpressure protection, and verification of MAOP-related records. Also, clarify records preparation and retention requirements.
7. Launcher/Receiver Pressure Relief – Require any launcher or receiver for inline tools be equipped with a device capable of safely relieving pressure in the barrel before opening of the launcher or receiver barrel closure or flange and insertion or removal of inline inspection tools, scrapers, or spheres. Require the use of a suitable device to indicate that pressure has been relieved in the barrel, or provide a means to prevent opening of the barrel closure or flange, or prevent insertion or removal of inline inspection tools, scrapers, or spheres, if pressure has not been relieved. These requirements would enhance safety when performing maintenance and inspection activities that utilize launchers and receivers to insert and remove maintenance tools

and devices.

8. Expansion of Regulated Gas Gathering Pipelines
    a. Revise the current definition of a "gas gathering line," including repealing the use of API RP 80 as the regulatory basis for identifying regulated onshore gas gathering lines.
    b. Create a new category of "Type A"[14] regulated onshore gas gathering lines made up of the relatively higher risk lines that are not currently regulated.
    c. Repeal the current exemption for certain gas gathering lines for the immediate notice and reporting of incidents, the reporting of safety-related conditions (SRC) and annual pipeline summary data, and reporting into PHMSA's national registry of pipeline operators.

These changes would improve the safety and protection of pipeline workers, the public, property, and the environment by improving the detection and remediation of unsafe conditions, mitigating the adverse effects of pipeline failures, and ensuring that certain currently unregulated pipelines are subject to appropriate regulatory oversight. In addition to safety benefits, the rule will improve and extend the economic life of critical pipeline infrastructure that transports domestically produced natural gas energy, thus supporting national energy economic and security objectives.

1.3 ORGANIZATION OF REPORT

The remainder of the body of this report is organized as follows:

- Section 2, Regulatory Analysis, describes the purpose of the analysis, baseline, study period, and alternatives.
- Section 3, Analysis of Costs, discusses the need for the regulation, the impact of the regulation, assumptions underlying the cost analysis, and detailed estimates of costs for Topic Areas 1 through 7 (gas transmission provisions).
- Section 4, Analysis of Benefits, provides analysis of safety and environmental [avoided greenhouse gas (GHG) emissions] benefits from Topic Areas 1 through 7 (gas transmission provisions).
- Section 5, Comparison of Benefits and Costs for Topic Areas 1 through 7, provides a comparison of the estimated benefits and costs for the gas transmission provisions.
- Section 6, Benefit Pertaining to Topic Area 8, provides analysis of safety and environmental (avoided GHG emission) benefits from the gas gathering provisions.
- Section 7, Benefit-Costs Analysis Pertaining to Topic Area 8, provides a comparison of benefits and costs for the gas gathering provisions.
- Section 8, Evaluation of Unfunded Mandate Act Considerations, provides analysis of potential state costs.

Several appendices provide supplemental information:

[14] Type A and Type B onshore gathering lines are defined in 49 CFR 192.8.

- Appendix A, Supplemental Calculations for Estimation of Topic Area 1 Costs
- Appendix B, Social Costs of Greenhouse Gas Emissions
- Appendix C, Rate of Incident Prevention as a Function of Assessment Mileage
- Appendix D, Consequences of San Bruno Incident
- Appendix E, Consequences of Historical Incidents.

2. REGULATORY ANALYSIS

This section describes the purpose of the analysis, the baseline for measuring the incremental impact of the proposed rule, the timeframe and structure of the analysis, including alternatives.

All data, unless otherwise stated, is obtained from annual reports, incident reports, or IMP performance metrics submitted to PHMSA by pipeline operators as required by 49 CFR Parts 191, 192, and 195.

2.1 PURPOSE OF THE ANALYSIS

U.S. Code, Title 49, Chapter 601, Section 60102 specifies that the Department of Transportation (DOT), when prescribing any pipeline safety standard shall consider relevant available gas and hazardous liquid pipeline safety information, environmental information, the appropriateness of the standard, and the reasonableness of the standard. In addition, DOT must, based on a risk assessment, evaluate the reasonably identifiable or estimated benefits and costs expected to result from implementation or compliance with the standard. This preliminary Regulatory Impact Analysis fulfils this statutory requirement.

Executive Order 12866 of September 30, 1993, Regulatory Planning and Review, directs all Federal agencies to assess the benefits and costs of "significant regulatory actions," and assess the benefits and costs of alternatives for rules expected to have an annual impact on the economy of $100 million or more. The Executive Order also requires a determination as to whether a proposed rule could adversely affect the economy or a section of the economy in terms of productivity and employment, the environment, public health, safety, or State, local, or tribal governments. Furthermore, the Regulatory Flexibility Act of 1980, as amended, requires Federal agencies assess the economic impact of proposed rules on small entities. The UMRA also requires an impact analysis for rules that that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $153 million or more ($100 million in 1995 dollars, adjusted for inflation for 2013) in any one year.

In accordance with the above directives, this analysis examines the potential compliance costs and benefits of the proposed rule and other feasible regulatory alternatives.

2.2 BASELINE FOR THE ANALYSIS

The proposed rule would apply to gas transmission and gathering pipelines. The current infrastructure in the United States for regulated gas transmission and gathering pipelines is characterized in the tables below.

Table 2-1 Pipeline Infrastructure - Gas Transmission (2015)

System Type	Onshore Miles	Total Miles	Number of Operators
Interstate	192,217	196,033	156
Intrastate	105,668	105,757	891
Total	297,885	301,790	See note 1

Source: PHMSA Pipeline Data Mart
1. Entities may operate both inter- and intrastate pipelines. There are 1,017 total operators.

Table 2-2 Pipeline Infrastructure - Regulated Onshore Gas Gathering (2015)			
Type A Miles[1]	**Type B Miles**[2]	**Total Miles**	**Number of Operators**
7,844	3,580	11,424	367

Source: PHMSA Pipeline Data Mart
1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations

The IMP rule, "Pipeline Safety: Pipeline Integrity Management in High Consequence Areas,"[15] is the previous significant gas transmission pipeline rulemaking related to most of the requirements in the proposed rule. The Integrity Management (IM) requirements in 49 CFR Part 192, Subpart O specify how pipeline operators must identify, prioritize, assess, evaluate, repair and validate, through comprehensive analyses, the integrity of gas transmission pipelines in HCAs. Although operators may voluntarily apply IM practices to pipeline segments that are not in HCAs, the regulations do not require operators to do so.

Currently, approximately 7% of onshore gas transmission pipelines are located in HCAs. However, coincident with integrity assessments of HCA segments, pipeline operators have assessed substantial amounts of pipeline in non-HCA segments. The Interstate Natural Gas Association of America (INGAA), a trade group representing approximately 200,000 miles of interstate natural gas pipelines, noted in its ANPRM comments that approximately 90% of members' Class 3 and 4 pipeline mileage not in HCAs are presently assessed through testing during IM assessments.[16] This is because ILI and pressure testing cover large continuous pipeline segments which may contain both HCA mileage and non-HCA mileage. Operators may also have assessed non-HCA mileage for various other reasons.

Separately, based on the IM principle of continuous improvement, INGAA members committed to extend by 2012 some level of IM to pipeline segments where approximately 90% of people who live, work or otherwise congregate within the potential impact radius (PIR) of a given pipeline. INGAA members have committed to apply full IM programs to those segments by 2020. Assessment and repair reporting in operators' annual report submissions suggest that operators are assessing a significant amount of miles outside of HCAs. [17]

With respect to gas gathering pipelines, the current baseline is PHMSA's "Gas Gathering Line Definition; Alternative Definition for Onshore Lines and new Safety Standards," (Final Rule effective April 14, 2006).[18] In that rule PHMSA distinguished regulated onshore

[15] [68 FR 69778] 49 CFR Part 192 [Docket No. RSPA–00–7666; Amendment 192–95] Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)
[16] See http://www.ingaa.org/about.aspx. Refers to assessing non-HCA segments in conjunction with integrity assessments of HCA segments, by virtue of the proximity and continuity of the segments.
[17] For example, 2014 reports show that operators assessed approximately 26,000 miles using metal loss ILI tools, ECDA, pressure tests, and other methods.
[18] [71 FR 13289] 49 CFR Part 192 [Docket No. PHMSA–1998–4868; Amendment 192–102] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards

gathering lines from other gas pipelines and production operations. PHMSA also established safety rules for certain onshore gathering lines in rural areas and revised current rules for certain onshore gathering lines in non-rural areas.

2.3 TIME PERIOD OF THE ANALYSIS

The proposed rule would require that gas transmission pipeline operators conduct additional integrity assessments of an estimated 16,600 miles of gas transmission pipeline. The proposed rule would also establish a deadline for completing the initial assessments within 15 years of the effective date of the rule, and require operators to reassess pipelines in newly defined "moderate consequence areas" more than 20 years after the previous assessment. Therefore, this analysis evaluates the costs and benefits for the 15-year initial compliance period and used the same time frame for all topic areas for both gas transmission and gas gathering pipelines.

2.4 ALTERNATIVES

In general, PHMSA considered relaxed compliance deadlines and/or 'no action' alternatives for each topic area.

For Topic Area 1, PHMSA considered a broader scope intended to address more pipe segments to which NTSB Recommendations P-11-14 and P-11-15 would apply. Several other alternatives underwent a screening evaluation.

For Topic Area 8 (expansion of regulated gas gathering lines), PHMSA also considered applying some safety regulations to all currently unregulated gas gathering lines (instead of restricting the new regulations to a subset of lines).

The alternatives considered by PHMSA, and the rationale for not selecting those alternatives, are discussed in more detail for each topic area in Sections 5.6 (gas transmission) and 7.6 (gas gathering).

3. ANALYSIS OF COSTS

This section provides detailed analysis for each topic area and includes a summary of the proposed regulatory changes, the need for the regulations (problem statement), assessment of the incremental impact, assumptions underlying the analysis, and the data, method, and resulting estimates of incremental cost.

3.1 RE-ESTABLISH MAOP, VERIFY MATERIAL PROPERTIES, AND INTEGRITY ASSESSMENT OUTSIDE HCAS

Topic Area 1 includes the following proposed changes to the current regulations:

1. Addition of "moderate consequence area" (MCA) and "occupied site" definitions to be used to determine the scope of pipelines subject to the assessment requirements in 49 CFR § 192.710, the MAOP verification requirements in 192.624, and the material documentation requirements in 192.607. [§ 192.3]
2. Material documentation requirements for segments that lack adequate documentation. [§ 192.607]
3. Re-verification of MAOP, which in most cases would require an integrity assessment that meets specific requirements, or equivalent. [§§ 192.619(e) and 192.624]
4. Non-HCA assessments. [§ 192.710]
    a. Data analysis requirements for assessments conducted (same as HCA)
    b. Assessment methods (same as HCA)
5. Repair requirements and schedules for non-HCA anomalies and conditions discovered as a result of the assessments required by 49 CFR § 192.710 or 192.624. [§ 192.711, § 192.713]
    a. Immediate conditions (same as HCA)
    b. Two year conditions (same as one year conditions in HCA)

3.1.1 PROBLEM STATEMENT

PHMSA developed the proposed regulations in Topic Area 1 to address a number of statutory provisions and NTSB recommendations:

- The Act §23(d) (Issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in high-consequence areas and operating at a pressure greater than 30% of SMYS.)
- The Act §23(c) (Require the operator to reconfirm MAOP as expeditiously as economically feasible; and determine what actions are appropriate for the pipeline owner or operator to take to maintain safety until a maximum allowable operating pressure is confirmed.)
- The Act §5(a) and §5(f) (Evaluate whether integrity management system requirements, or elements thereof, should be expanded beyond HCAs, and issue final regulations if the Secretary finds that integrity management system requirements, or elements thereof, should be expanded beyond HCAs.)
- NTSB Recommendation P-11-14 (Amend 49 CFR § 192.619 to delete the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.)

- NTSB Recommendation P-14-1 (Add principal arterial roadways including interstates, other freeways and expressways, and other principal arterial roadways as defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures to the list of "identified sites" that establish a HCA.)

These mandates and recommendations are related: all address pipeline integrity under operating conditions. 49 CFR Part 192, Subpart O requires periodic integrity assessments for pipe segments located in HCAs (approximately 20,000 of 300,000 miles, or seven percent, of onshore gas transmission pipelines). Part 192 does not require integrity assessments of pipeline segments that are not in HCAs. The proposed rule would require operators to conduct integrity assessments for onshore non-HCA segments within 15 years of the effective date of the rule, and every 20 years thereafter.

The proposed rule would establish a newly-defined MCA to identify additional non-HCA pipeline segments that would require integrity assessments. MCA means an onshore area that is within a potential impact circle, as defined in § 192.903, containing five or more buildings intended for human occupancy, an occupied site, or a right-of-way for a designated interstate, freeway, expressway, and other principal four-lane arterial roadway as defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures, and does not meet the definition of HCA. Requirements for data analysis, assessment methods, and immediate repair conditions would be similar to requirements for HCA segments. Two-year repair conditions for MCA segments would be the same as one-year repair conditions for HCA segments. These changes would ensure the prompt remediation of anomalous conditions that could potentially impact people, property, or the environment, commensurate with the severity of the defects, while allowing operators to allocate their resources to HCAs on a higher-priority basis.

The proposed rule would require operators to verify or establish material properties for pipelines in HCAs and Class 3 and Class 4 locations for which adequate documentation is missing or unavailable. Operators can take advantage of opportunities where pipe segments are exposed for maintenance or repair (e.g., to repair defects identified during an integrity assessment), to conduct tests and examinations to confirm and document key properties and attributes of the pipeline.

Operators of segments in HCAs or MCAs for which MAOP was established in accordance with § 192.619(c) or otherwise do not have an adequate basis for the existing MAOP would be required to re-establish or re-validate MAOP through pressure testing or other means as defined in the proposed rule. In almost every case, this would require integrity assessment and repair of discovered defects. Assessments conducted for these purposes could be credited toward meeting other integrity assessment requirements found in 49 CFR Part 192, Subpart O, or the proposed § 192.710.

3.1.2 ASSESSMENT OF REGULATORY IMPACT

The largest impact of Topic Area 1 is the integrity assessment of pipe for which MAOP must be re-established, and for segments located in newly defined MCAs for which MAOP does not need to be confirmed. The proposed rule would include specific repair criteria for timely remediation of pipeline defects discovered through integrity assessments, and material documentation requirements.

Coincident with integrity assessments of HCA segments, pipeline operators have assessed substantial amounts of pipeline in non-HCA segments. The proposed rule would allow the use of those prior assessments for non-HCA segments in complying with the new requirements. PHMSA accounted for this circumstance in this analysis.

There is some overlap of the proposed requirements (i.e., integrity assessment activities serve to comply with multiple requirements) in this Topic Area. However, to help understand the relative scope of each requirement, PHMSA evaluated each separately:

- Section 3.1.4 addresses the Act §23(d)
- Section 3.1.5 addresses the Act §23(c)
- Section 3.1.6 addresses the Act §5(a) and §5(f)
- Section 3.1.7 addresses NTSB Recommendation P-11-14.

NTSB Recommendation P-14-1 is addressed via the MCA definition which informs and establishes the scope of pipeline segments to which the proposed requirements apply.

3.1.3 ANALYSIS ASSUMPTIONS

The sections below present analysis of the incremental cost of the proposed changes. To estimate costs, PHMSA assumed that certain characteristics of pipelines in HCAs apply to non-HCA pipe and combined this information with data collected on regulated pipelines from operator annual reports to approximate the scope and condition of the non-HCA lines to be assessed under the proposed rule. These assumptions were necessary because data for non-HCA segments is limited, and there is no data related to the population of pipelines that could meet the new definition for MCA.

Because operators must already repair pipeline defects that are injurious to the pipe, the specific repair criteria proposed by PHMSA do not represent new repair standards, but affect the timeliness of repairs. The cost of performing repairs of defects discovered as a result of the mandatory integrity assessments is therefore baseline operating and maintenance requirements. (Repair costs are also not included in baseline incident costs used to estimated benefits. See Appendix E for a fuller discussion.) The only cost to operators of implementing the repair timeliness criteria is the time cost of money for completing some repair more quickly than an operator might have done prior to this rulemaking. This cost is negligible compared to the cost of conducting assessments.

The analysis is based on the assumption that all defects discovered by the testing and assessment requirements would be either repaired or result in an incident. Performing repairs sooner than in the absence of the proposed rule, and thus averting incidents, is the basis for the estimated benefits. It is possible that such repairs could be required on pipelines that, absent the rule, operators would replace before discovering the defects. PHMSA invites comments on these issues and costs.

Because operators must have already performed analysis in order to have identified HCAs, or verify that they have no HCAs, PHMSA assumed that the cost of identifying MCAs is negligible compared to the cost of assessments and did not quantify the cost to identify MCAs.

3.1.4 ESTIMATION OF COMPLIANCE COSTS TO RE-ESTABLISH MAOP: PREVIOUSLY UNTESTED PIPE

Topic Area 1 addresses the statutory requirement in the Act §23(d), which requires that PHMSA issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in high-consequence areas and operating at a pressure greater than 30 percent of SMYS. In developing the regulations, PHMSA considered safety testing methodologies, including pressure testing and other alternative methods, including in-line inspections that are of equal or greater effectiveness. PHMSA would allow operators to select from several methods. The primary methods PHMSA expects operators to use would be ILI in conjunction with an engineering critical assessment (ECA) or pressure testing. Other options were provided in the rule (such as replacing the pipeline or derating the pipeline). However, these other options are extreme measures, and more costly; hence PHMSA expects operators to use ILI/ECA or pressure testing for virtually all segments to which these requirements would apply. The rule also would establish timeframes for the completion of such testing that take into account potential consequences to public safety and the environment and that minimize costs and service disruptions.

PHMSA used the following steps to estimate costs of assessments to re-establish MAOP:

1. Estimate the mileage of previously untested pipe segments.
2. Estimate the breakdown of assessment methods.
3. Estimate the unit costs of each assessment method.
4. Estimate total incremental compliance costs.

3.1.4.1 Estimation of Mileage of Previously Untested Pipe

Operators report the mileage of pipeline segments in HCAs that were not pressure tested to establish MAOP. To estimate the mileage subject to the requirement, PHMSA proportionally adjusted the mileage in each class location[19] by the proportion of pipe operated at an MAOP greater than 30% SMYS, also reported by operators (**Table 3-1**). **Table 3-2** shows the resulting estimate of applicable pipe.

Table 3-1. Onshore Gas Transmission Mileage by Percent SMYS

Location	Total	<20% SMYS	20-30% SMYS	>30% SMYS	Percent >30% SMYS
Interstate					
Class 1	160,381	6,750	7,975	145,656	91%
Class 2	17,811	1,460	1,433	14,918	84%
Class 3	13,925	1,302	1,305	11,319	81%
Class 4	29	4	9	16	55%
Total	192,146	9,516	10,722	171,908	89%
Intrastate					
Class 1	72,254	7,975	8,245	56,034	78%
Class 2	12,820	1,065	2,737	9,018	70%

[19] Class Locations are defined in 49 CFR §192.5 and are based primarily on housing density near the pipe segment. Class 1 has the lowest density while Class 4 locations are the densest. Suburban residential areas are typically Class 2 or Class 3 locations.

Table 3-1. Onshore Gas Transmission Mileage by Percent SMYS					
Location	**Total**	**<20% SMYS**	**20-30% SMYS**	**>30% SMYS**	**Percent >30% SMYS**
Class 3	19,726	2,241	5,610	11,876	60%
Class 4	880	23	427	430	49%
Total	105,680	11,303	17,019	77,358	73%
Source: 2014 PHMSA Gas Transmission Annual Report SMYS = specified minimum yield strength					

Table 3-2. Estimate of Previously Untested Onshore Gas Transmission Mileage in HCAs Operating at Greater than 30% SMYS			
Location	**Previously Untested HCA[1]**	**Percent >30% SMYS**	**HCA ≥ 30% SMYS[2]**
Interstate			
Class 1	62	91%	59
Class 2	23	84%	19
Class 3	439	81%	357
Class 4	0	55%	0
Total	524	89%	432
Intrastate			
Class 1	13	78%	10
Class 2	18	70%	13
Class 3	749	60%	451
Class 4	5	49%	3
Total	786	73%	476
HCA = High consequence area SMYS = specified minimum yield strength 1. Source: PHMSA 2014 Annual Report 2. See Appendix A.			

3.1.4.2 Estimation of Breakdown of Assessment Methods

The methods specified in the proposed rule (§ 192.624) include pressure testing to include a spike pressure test (§ 192.506) if the pipeline includes legacy pipe or is constructed using legacy construction techniques, or if there has been a reportable in-service incident (§ 191.3) since the most recent successful pressure test due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect. For modern pipe without the aforementioned risk factors, a pressure test in accordance with § 192.505 would be allowed. The proposed rule would also allow operators to re-establish MAOP by the use of an ILI program in conjunction with an ECA process (using technical criteria to establish a safety margin equivalent to a pressure test). Other methods to re-establish MAOP would also be allowed, including de-rating or replacing the pipe segment, or use of other technology that the operator demonstrates provides an equivalent or greater level of safety. However, PHMSA determined that the cost of pipe replacement or derating would be greater than the pressure test and ILI/ECA test methods (pipe replacement costs are presented in Table 3-63; derating would result in substantial revenue loss to operators.)

PHMSA estimated compliance costs assuming that operators would re-establish MAOP by

ILI/ECA for pipelines able to accommodate ILI tools, commonly referred to as "smart pigs" (i.e., they are "piggable"), upgrading to accommodate ILI tools, or a pressure test. Beginning in 2012, PHMSA required operators to report pipeline mileage that is piggable (**Table 3-3**). PHMSA used this data to estimate the mileage that would be assessed by ILI as-is. PHMSA assumed that operators would comply through use of ILI on segments that are piggable given the lower costs associated with ILI assessments.

Table 3-3: Percent of Miles Capable of Accepting an Inline Inspection Tool

Class Location	HCA	Non- HCA
Interstate		
Class 1	95%	71%
Class 2	94%	70%
Class 3	89%	60%
Class 4	94%	56%
Intrastate		
Class 1	68%	53%
Class 2	66%	40%
Class 3	55%	33%
Class 4	49%	62%
Source: PHMSA 2014 Gas Transmission Annual Report		

Beginning in 2010, PHMSA required operators to report the type of assessment method used to perform integrity assessments. The breakdown of mileage assessed by each assessment method for 2010-2014 is presented in **Table 3-4**. The relatively high percentage of intrastate pipeline assessed by pressure test and direct assessment in the 2010-2014 time period is attributed to the fact that a larger percentage of intrastate pipelines are unable to accommodate ILI tools (i.e., they are not "piggable").

Table 3-4. Miles of Onshore Gas Transmission Pipeline for which Integrity Assessment was Conducted (2010-2014)

Year	ILI	Pressure Test	Direct	Other	Total
Interstate					
2010	15,308	567	177	85	16,136
2011	17,366	829	157	29	18,380
2012	18,656	846	126	42	19,670
2013	15,687	739	106	144	16,675
2014	15,820	1,008	116	11	16,954
Total	82,837 (94%)	3,988 (5%)	681 (0%)	309 (0%)	87,816 (100%)
Intrastate					
2010	4,792	826	1,539	1,191	8,348
2011	3,920	858	1,842	1,046	7,666
2012	5,041	1,232	2,085	2,570	10,929
2013	5,663	763	1,894	782	9,100
2014	5,801	807	1,641	750	8,998

Table 3-4. Miles of Onshore Gas Transmission Pipeline for which Integrity Assessment was Conducted (2010-2014)					
Year	**ILI**	**Pressure Test**	**Direct**	**Other**	**Total**
Total	25,218 (56%)	4,486 (10%)	9,000 (20%)	6,338 (14%)	45,042 (100%)
Source: PHMSA Gas Transmission Annual Reports: 2010-2014					

For pipelines that are not piggable, PHMSA assumed that operators would either pressure test the segment or upgrade it to accommodate an ILI tool. PHMSA applied its experience with historical piggability and assessment methods to estimate the percent of miles which will be pressure tested and upgraded to ILI under the proposed rule (**Table 3-5**).

Table 3-5. Estimated Assessment Method for Previously Untested Pipe in High Consequence Areas (Percent of Mileage)			
Location	**ILI [1]**	**Pressure Test[2]**	**ILI Upgrade[2]**
Interstate			
Class 1	95%	5%	0%
Class 2	94%	5%	1%
Class 3	89%	5%	6%
Class 4	94%	0%	6%
Intrastate			
Class 1	68%	10%	22%
Class 2	66%	20%	14%
Class 3	55%	20%	25%
Class 4	49%	21%	30%
1. Source: PHMSA 2014 Gas Transmission Annual Report 2. PHMSA best professional judgment based on historical piggability and assessment methods (Tables 3-3 and 3-4).			

PHMSA assumed that operators would assess an equal percent of mileage in each year of the 15-year compliance period. Therefore the annual cost of any given component is the total cost divided by 15 years. This assumption may result in an overestimate of discounted costs and benefits as operators may elect to complete costlier or more complex assessments such as pressure tests and ILI upgrades later in the program period.

3.1.4.3 Estimation of Unit Costs of Assessment

This section describes the estimation of unit costs for assessment methods.

Upgrade to ILI

PHMSA developed unit costs to upgrade to accommodate ILI and run ILI tools based on best professional judgment (BPJ). PHMSA developed estimates of the overall average unit ILI upgrade components and costs by pipeline category. These estimates represent a national average cost for each category, and are comprehensive of all upgrade costs, including materials, labor, right of way agreements and permitting, and cleanup.[20]

[20] Based on design pressure of 800 pounds (no more than 1000 pounds) and fittings of ANSI 600.

Additionally, upgrading pipelines generally requires operators to empty the natural gas from the pipeline via a procedure called "blowdown" which entails releasing natural gas into the atmosphere. PHMSA calculated the amount of gas that would be released through this procedure per mile using **Equation 1**.

Equation 1: $\boldsymbol{Vb = (28.798 * (Tb/Pb) * (Pavg/(Zavg * Tavg)) * D^2)/1000}$

Where:

Vb = Volume of gas released per mile (thousand cubic feet; MCF)

Tb = Temperature at standard conditions (70 degrees F)

Pb = Pressure at standard conditions (14.7 pounds per square inch; PSI)

Pavg = Pressure at blowdown conditions (100 PSI for intrastate; 150 PSI for interstate)

Zavg = Compressibility factor at packed conditions (0.88)

Tavg = Temperature at packed conditions (70 degrees F)

D = inside diameter of pipeline in inches (29.25 for 30-inch pipes, 15.25 for 16-inch pipes, and 7.5 for 8-inch pipes)

To value the gas lost during upgrade and inspection-related blowdown, PHMSA used data on the volume and cost of gas released during intentional controlled blowdowns conducted as part of responding to or recovering from incidents, based on incident report data (Part A). Between 2010 and 2014, there were 294 incident reports that included intentional releases. PHMSA calculated the unit cost of natural gas for each case by dividing the cost of gas released intentionally[21] by the volume of gas released intentionally. The median natural gas price in these incidents was $4.21 per MCF. Note that this gas price may not be representative of the cost of gas released during planned controlled blowdowns for pipe upgrades, since operators may not be able to plan for incident-related blowdowns as cost-effectively as they would for planned pipeline upgrades. As such, this approach may result in an overestimate of blowdown costs associated with upgrades.

The gas lost during blowdown represents GHG emissions which have additional, external costs to society. PHMSA accounted for these additional social costs separately, and they are not reflected in the unit costs described in this section.

Table 3-6 shows the calculated unit costs (i.e., cost per mile) including both upgrade and blowdown costs for pipelines in Class 1 and Class 2 non-HCA locations. The estimates range from $14,700 to $78,700 per mile, depending on the pipeline type (inter- and intrastate) and diameter. **Table 3-7** shows the calculated unit costs for pipelines in Class 3 and Class 4 locations and Class 1 and Class 2 HCA locations, with estimates ranging from $20,600 to $168,600 per mile. PHMSA invites comments on the accuracy of these estimates.

Table 3-6. Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 1 and Class 2 Non-HCA Pipelines[1]

	Interstate Segment			**Intrastate Segment**		
	26" - 48"	**14" - 24"**	**4" - 12"[2]**	**26" - 48"**	**14" - 24"**	**4" - 12"[2]**
Diameter (inches)	30	16	8	30	16	8

[21] Updated to 2014 dollars using the Consumer Price Index.

Table 3-6. Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 1 and Class 2 Non-HCA Pipelines[1]

	Interstate Segment			Intrastate Segment		
	26" - 48"	14" - 24"	4" - 12"[2]	26" - 48"	14" - 24"	4" - 12"[2]
Pipe thickness (inches)	0.375	0.375	0.25	0.375	0.375	0.25
Segment Miles	60	60	60	30	30	30
Number of Mainline Valves	3	3	3	2	2	2
Number of Bends	3	3	3	3	3	3
Cost per Mainline Valve	$338,000	$220,000	$89,000	$338,000	$220,000	$89,000
Cost per Bend	$60,000	$32,000	$16,000	$60,000	$32,000	$16,000
Cost of Launcher	$741,000	$481,000	$280,000	$741,000	$481,000	$280,000
Cost of Receiver	$741,000	$481,000	$280,000	$741,000	$481,000	$280,000
Total Upgrade Cost[3]	$2,676,000	$1,718,000	$875,000	$2,338,000	$1,498,000	$786,000
Upgrade Costs per Mile	$44,600	$28,633	$14,583	$77,933	$49,933	$26,200
Gas Released per Mile (MCF)[4]	286	78	19	190	52	13
Cost of Gas Released per Mile[5]	$1,203	$327	$79	$802	$218	$53
Total Unit Cost (per mile)[6]	**$45,803**	**$28,960**	**$14,662**	**$78,735**	**$50,151**	**$26,253**

HCA = high consequence area
MCF = thousand cubic feet
1. Based on best professional judgment of PHMSA staff, and includes excavation, permitting, construction, and cleanup costs. Unit cost of gas released based on incident reports.
2. Pipelines below 4" generally cannot accommodate in-line inspection and will be exempt from requirements.
3. Total upgrade cost calculated as cost of launcher plus cost of receiver plus cost per bend multiplied by number of bends plus cost per mainline valve and number of mainline valves.
4. Based on Equation 1 using temperature (70 degrees F), pressure (14.7 PSIA at standard conditions; 50 PSI at blowdown conditions), and compressibility (factor of 0.88 at packed conditions) assumptions.
5. Assumes a natural gas cost of $4.21 per MCF, based on the cost of gas released intentionally during a controlled blowdown as part of a response to an incident (median of costs based on data for 294 incidents). Does not include the social cost of methane released.
6. Upgrade costs per mile plus cost of gas released during blowdown per mile.

Table 3-7. Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 3 and Class 4 Pipelines and Class 1 and Class 2 HCA Pipelines[1]

	Interstate Segment			Intrastate Segment		
	26" - 48"	14" - 24"	4" - 12"[2]	26" - 48"	14" - 24"	4" - 12"[2]
Diameter (inches)[2]	30	16	8	30	16	8
Segment Miles	45	45	45	15	15	15
Number of Mainline Valves	3	3	3	2	2	2
Number of Bends	6	6	6	6	6	6

Table 3-7. Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 3 and Class 4 Pipelines and Class 1 and Class 2 HCA Pipelines[1]						
	Interstate Segment			**Intrastate Segment**		
	26" - 48"	**14" - 24"**	**4" - 12"[2]**	**26" - 48"**	**14" - 24"**	**4" - 12"[2]**
Cost per Mainline Valve	$338,000	$220,000	$89,000	$338,000	$220,000	$89,000
Cost per Bend	$60,000	$32,000	$16,000	$60,000	$32,000	$16,000
Cost of Launcher	$741,000	$481,000	$280,000	$741,000	$481,000	$280,000
Cost of Receiver	$741,000	$481,000	$280,000	$741,000	$481,000	$280,000
Total Upgrade Cost[3]	$2,856,000	$1,814,000	$923,000	$2,518,000	$1,594,000	$834,000
Upgrade Costs per Mile	$63,467	$40,311	$20,511	$167,867	$106,267	$55,600
Gas Released per Mile (MCF)[4]	286	78	19	190	52	13
Cost of Gas Released per Mile[5]	$1,203	$327	$79	$802	$218	$53
Total Unit Cost (per mile)[6]	**$64,669**	**$40,638**	**$20,590**	**$168,668**	**$106,485**	**$55,653**

HCA = high consequence area
MCF = thousand cubic feet
PHMSA = Pipeline and Hazardous Materials Safety Administration
1. Based on best professional judgment of PHMSA staff, and includes excavation, permitting, construction, and cleanup costs. Unit cost of gas released based on incident reports.
2. Pipelines below 4" generally cannot accommodate in-line inspection and will be exempt from requirements.
3. Total upgrade cost calculated as cost of launcher plus cost of receiver plus cost per bend multiplied by number of bends plus cost per mainline valve and number of mainline valves.
4. Based on Equation 1 using temperature (70 degrees F), pressure (14.7 PSIA at standard conditions; 50 PSI at blowdown conditions), and compressibility (factor of 0.88 at packed conditions) assumptions.
5. Assumes a natural gas cost of $4.21 per MCF, based on the cost of gas released intentionally during a controlled blowdown as part of a response to an incident (median of costs based on data for 294 incidents). Does not include the social cost of methane released.
6. Upgrade cost plus cost per mile plus the cost of gas release per mile.

PHMSA used diameter data for interstate and intrastate gas transmission pipelines to calculate weighted average per-mile cost to upgrade segments to accommodate an ILI tool. **Table 3-8** shows these estimates.

Table 3-8. Calculation of Weighted Average Unit Cost to Accommodate Inline Inspection Tools					
	Pipeline Diameter			**Weighted Average Cost per Mile**	
Type	**> 26"[1]**	**14" - 24"[1]**	**<12"[1]**	**Class 1, 2, Non-HCA[2]**	**Class 3, 4, HCA[2]**
Interstate	41%	32%	27%	$31,930	$44,972
Intrastate	14%	29%	57%	$40,512	$86,176

1. Source: PHMSA 2014 Gas Transmission Annual Report
2. Based on Tables 3-6 and 3-7.

For comparison, some natural gas pipeline operators have provided information on costs to upgrade unpiggable pipelines to accommodate ILI, including Pacific Gas and Electric (PG&E; as cited in American Gas Association (AGA), 2011; Appendix 2, Table 2-1) and Southern California Gas Company and San Diego Gas & Electric Company (SoCal, 2011; Table O). The information provided by PG&E indicates a unit cost of approximately $153,000 per mile, which is within the range calculated above for pipelines in Class 3 and Class 4 locations and Class 1 and Class 2 HCA locations. SoCal provided information on the cost to upgrade pre-1946 constructed mileage in Southern California.[22] The unit cost PHMSA calculated from the SoCal information ($4.4 million to $4.7 million per mile) may represent site-specific conditions that are not representative of the costs elsewhere and over a wide range of pipeline facilities.

According to INGAA (2015), factors affecting the unit costs include the location of the pipeline, type of labor (e.g., unionized versus nonunionized), what needs to be retrofitted (e.g., diameter changes in segment versus valve replacements), pipeline configuration, and pipe size. In response to a request for information from PHMSA, INGAA reported that unit costs to retrofit pipelines to accommodate ILI are highly variable, ranging from $50,000 to $1 million per mile (INGAA, 2015). Although the low end of this range is comparable to the costs shown above, the high end is considerably higher. However, PHMSA did not incorporate these cost estimates into the analysis since information is not available about the components and wider applicability of the costs, or is insufficient.

As described above, operators will have to blowdown a pipeline segment in order to safely make the necessary upgrades to permit a line to accept an inline inspection tool.

<u>ILI</u>

PHMSA assumed an operator would run three ILI tools per assessment consistent with its proposal for ILI assessments performed to re-establish MAOP in accordance with § 192.624. However, the use of three tools might not be required for an assessment conducted in accordance with § 192.710. In those cases, the estimate in **Table 3-9** might be high.

Table 3-9. Estimated Unit Cost of ILI

Component	Interstate (60-mile) Segment			Intrastate (30-mile) Segment		
	26" - 48"	14" - 24"	4" - 12"	26" - 48"	14" - 24"	4" - 12"
Mobilization[1]	$15,000	$12,500	$10,000	$15,000	$12,500	$10,000
Base MFL tool[2]	$90,000	$72,000	$54,000	$45,000	$36,000	$27,000
Additional combo tool (deformation & crack tools)	$45,000	$36,000	$27,000	$22,500	$18,000	$13,500
Reruns	$40,000	$30,000	$20,000	$40,000	$30,000	$20,000
Analytical and data integration services	$80,000	$80,000	$80,000	$40,000	$40,000	$40,000
Operator preparation [3]	$27,000	$23,050	$19,100	$16,250	$13,650	$11,050
Total	**$297,000**	**$253,550**	**$210,100**	**$178,750**	**$150,150**	**$121,550**

Source: PHMSA best professional judgment.
1. Mobilization is the cost for mobilization and demobilization of the construction work crew, material and equipment to and from the work site. Regional differences may apply.
2. Typically $900 to $1,500 per mile.

[22] Due to technical difficulties associated with SoCal's remaining unpiggable pipeline mileage, SoCal has elected to replace the pipes rather than retrofit to accommodate ILI. SoCal estimated replacement costs for pre-1946 pipeline segments using a cost matrix based on pipe diameter and length.

Table 3-9. Estimated Unit Cost of ILI						
	Interstate (60-mile) Segment			Intrastate (30-mile) Segment		
Component	26" - 48"	14" - 24"	4" - 12"	26" - 48"	14" - 24"	4" - 12"
3. Includes analysis, specifications, cleaning pigs, fatigue crack growth analysis, etc. Estimated as 10% of cost of ILI and related data analysis.						

As with the ILI upgrade cost PHMSA calculated a weighted average per mile cost based on annual report data on pipe diameter (**Table 3-10**).

Table 3-10. Estimation of ILI Assessment Cost[1]				
Segment Type	Less than 12" Diameter	14" - 24" Diameter	Greater than 26" Diameter	Weighted Average Cost Per Mile
Interstate (60-mile segment)	27%	32%	41%	$4,324
Intrastate (30-mile segment)	57%	29%	14%	$4,594
1. Weighted average based on unit costs (see Table 3-9) and percentages of gas transmission mileage by diameter for inter and intrastate pipe from the 2014 Gas Transmission Annual Report.				

Pressure Test

PHMSA used vendor pricing data to develop unit costs for pressure testing.[23] Pressure test costs can also vary substantially, especially with respect to the section length being tested. Costs also vary by diameter of pipe size.

Table 3-11. Estimated Cost of Conducting Pressure Test ($2015)				
Pipe Diameter (inches)	Segment Length (miles)			
	1	2	5	10
12	$156,550	$159,706	$191,114	$286,355
24	$197,528	$205,927	$344,057	$378,893
36	$304,680	$362,229	$486,555	$670,248
Source: Greene's Energy Group, LLC (2013), updated to 2015 dollars using the Bureau of Labor Statistics US All City Average Consumer Price Index (2013=233.5; 2015=237.8). Includes mobilization; safety training; equipment setup; fill and stabilize pipeline; 8-hour hydrostatic test; dewater pipeline with carbon media filtration; clean and dry pipeline; disassemble equipment; clean up and de-mobilize.				

PHMSA added the cost of gas lost during pressure testing using Equation 1. **Table 3-12** and **Table 3-13** show these calculations for interstate and intrastate pipelines respectively.

Table 3-12. Volume of Gas Lost During Pressure Tests (MCF): Interstate Pipelines[1]				
Pipe Diameter (inches)	Segment Length (miles)			
	1	2	5	10
12	48.1	96.2	240.4	480.9
24	192.3	384.7	961.7	1,923.4
36	432.8	865.5	2,163.9	4,327.7
MCF = thousand cubic feet				

[23] Greene's Energy Group, LLC (2013). Budgetary Proposal. Various 12", 24" & 36" Pipelines Located In Nashville, Tennessee. Prepared for PHMSA.

Table 3-12. Volume of Gas Lost During Pressure Tests (MCF): Interstate Pipelines[1]				
Pipe Diameter (inches)	Segment Length (miles)			
	1	2	5	10
1. Estimated using Equation 1.				

Table 3-13. Volume of Gas Lost During Pressure Tests (MCF): Intrastate Pipelines[1]				
Pipe Diameter (inches)	Segment Length (miles)			
	1	2	5	10
12	32.1	64.1	160.3	320.6
24	128.2	256.5	641.1	1,282.3
36	288.5	577.0	1,442.6	2,885.1
MCF = thousand cubic feet 1. Estimated using Equation 1.				

Table 3-14 and **Table 3-15** show the cost of lost gas based on the estimated volumes of lost gas and a cost of gas of $5.71 per thousand cubic feet.[24]

Table 3-14. Cost of Lost Gas: Interstate Pipelines[1]					
Pipe Diameter (inches)	Segment Length (miles)				
	1 Mile	2 Mile	5 Mile	10 Mile	Average
12	$275	$549	$1,373	$2,746	$1,236
24	$1,098	$2,197	$5,491	$10,983	$4,942
36	$2,471	$4,942	$12,356	$24,711	$11,120
1. Calculated based on volume lost (see Table 3-12) times the cost of gas ($5.71 per thousand cubic feet).					

Table 3-15. Costs of Lost of Gas: Intrastate Pipelines[1]					
Pipe Diameter (inches)	Segment Length (miles)				
	1 Mile	2 Mile	5 Mile	10 Mile	Average
12	$183	$366	$915	$1,830	$824
24	$732	$1,464	$3,661	$7,322	$3,295
36	$1,647	$3,295	$8,237	$16,474	$7,413
1. Based on volume lost (see Table 3-13) times the cost of gas ($5.71 per thousand cubic feet).					

Infrequently, there may be a need to establish a temporary gas supply while a pipeline is out of service for testing as backup for a test that takes longer than expected. This need could occur if there is no alternative source of gas supply and demand is high, and would be more likely to occur at the end of a system where there are not multiple feeds coming into the line. More alternatives are likely in highly populated areas. The need for temporary gas supplies is most often encountered by intrastate pipeline operators, and they generally avoid pressure testing in such situations if other assessment methods are available. When required, operators may have to construct temporary lines or establish temporary compressed natural gas plants to supply gas.

[24] EIA: 2014 U.S. Natural Gas Citygate Price (dollars per thousand cubic feet).

The cost of providing a temporary gas supply can be very high when needed. PHMSA estimated approximately $1 million per test and, in order to account for this potential cost, assumed approximately ten percent of pressure tests would necessitate temporary gas supplies. Thus, PHMSA included in the unit cost estimates an average of $100,000 per test to approximate the cost of providing temporary gas supplies (at a cost of $1 million for ten percent of tests). Given that pressure tests are applicable under the proposed rule primarily in more populated areas, this assumption may overstate costs.

Table 3-16 and **Table 3-17** show the resulting total estimated costs for pressure tests for inter and intrastate pipelines, respectively. **Table 3-18** shows these costs on a per mile basis.

Table 3-16. Total Pressure Test Assessment Cost: Interstate Pipelines

Component	Segment Length (miles)			
	1	2	5	10
12 inch				
Pressure test[1]	$273,963	$279,486	$334,449	$501,120
Lost gas[2]	$275	$549	$1,373	$2,746
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$374,237	$380,035	$435,822	$603,866
24 inch				
Pressure test[1]	$345,673	$360,372	$602,100	$663,063
Lost gas[2]	$1,098	$2,197	$5,491	$10,983
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$446,772	$462,568	$707,591	$774,046
36 inch				
Pressure test[1]	$533,190	$633,902	$851,471	$1,172,933
Lost gas[2]	$2,471	$4,942	$12,356	$24,711
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$635,661	$738,844	$963,826	$1,297,645

1. Unit costs (see Table 3-11) plus 75% multiplier to account for operator costs for engineering test plan, procurement of pipe materials, right of way and agent costs, manifold installation costs, engineering and operational oversight, right of way clean up, and return the line to service.
2. See Tables 3-14.
3. Approximation of cost of temporary supply (up to $1 million) for 10% of tests.

Table 3-17. Total Pressure Test Assessment Cost: Intrastate Pipelines

Component	Segment Length (miles)			
	1	2	5	10
12 inch				
Pressure test[1]	$273,963	$279,486	$334,449	$501,120
Lost gas[2]	$183	$366	$915	$1,830
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$374,146	$379,852	$435,364	$602,951

Table 3-17. Total Pressure Test Assessment Cost: Intrastate Pipelines				
Component	**Segment Length (miles)**			
	1	**2**	**5**	**10**
24 inch				
Pressure test[1]	$345,673	$360,372	$602,100	$663,063
Lost gas[2]	$732	$1,464	$3,661	$7,322
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$446,406	$461,836	$705,760	$770,385
36 inch				
Pressure test[1]	$533,190	$633,902	$851,471	$1,172,933
Lost gas[2]	$1,647	$3,295	$8,237	$16,474
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$634,837	$737,196	$959,708	$1,289,407

1. Unit costs (see Table 3-11) plus 75% multiplier to account for operator costs for engineering test plan, procurement of pipe materials, right of way and agent costs, manifold installation costs, engineering and operational oversight, right of way clean up, and return the line to service.
2. See Tables 3-15.
3. Approximation of cost of temporary supply (up to $1 million) for 10% of tests.

Table 3-18. Per Mile Pressure Test Costs					
Pipe Diameter (inches)	**Segment Length (miles)**				
	1	**2**	**5**	**10**	**Average**
Interstate					
12	$373,963	$189,743	$86,890	$60,112	$177,677
24	$445,673	$230,186	$140,420	$76,306	$223,146
36	$633,190	$366,951	$190,294	$127,293	$329,432
Intrastate					
12	$374,146	$189,926	$87,073	$60,295	$177,860
24	$446,406	$230,918	$141,152	$77,039	$223,879
36	$634,837	$368,598	$191,942	$128,941	$331,079

Source: Tables 3-16 and 3-17 divided by miles per segment.

To use these per mile cost estimates in the analysis, PHMSA calculated a weighted average cost based on the breakdown of gas transmission pipeline infrastructure by pipe diameter using size data from gas transmission annual reports (**Table 3-19**).

Table 3-19 Weighted Average Unit Pressure Test Assessment Cost Per Mile[1]				
Segment Type	**<12" Diameter**	**14"-34" Diameter**	**36"+ Diameter**	**Average Cost**
Interstate	27%	57%	15%	$226,939
Intrastate	57%	37%	6%	$203,556

1. Weighted average based on unit costs (see Table 3-18) and percentages of gas transmission mileage by diameter for inter and intrastate pipe from the 2014 Gas Transmission Annual Report.

3.1.4.4 Estimation of Incremental Cost

Operators are already required to complete integrity management assessments of HCA segments under Subpart O of the Pipeline Safety Regulations. The MAOP re-verification tests required under the proposed rule would fulfil the operator's obligation to complete integrity management assessments. Therefore, estimation of incremental costs involves estimating total costs to re-establish MAOP, estimating baseline integrity management assessment costs, and subtracting to obtain incremental costs to re-establish MAOP.

Total Cost to Re-establish MAOP

To calculate total costs, PHMSA multiplied the estimated mileages by assessment method by the unit cost of assessments. In doing so, PHMSA used the 30-mile segment ILI unit costs for intrastate pipelines, and the 60-mile segment ILI unit costs for interstate segments. For pressure tests, PHMSA used the average cost across the one, two, five, and eight mile segment costs. PHMSA assumed that the assessments are equally distributed over the compliance period (i.e., 1/15th each year for 15 years). **Table 3-20** shows the results.

Table 3-20. Annual Costs to Re-establish MAOP, Previously Untested Pipe Operating at Greater than 30% SMYS in a HCA

Location	ILI	PT	Upgrade and ILI	Total
Interstate				
Class 1	$15,310	$42,321	$68	$57,699
Class 2	$5,175	$14,381	$228	$19,783
Class 3	$91,160	$270,169	$69,028	$430,356
Class 4	$59	$0	$43	$102
Subtotal	**$111,704**	**$326,870**	**$69,367**	**$507,940**
Intrastate				
Class 1	$1,986	$13,695	$4,670	$20,350
Class 2	$2,372	$34,064	$3,854	$40,291
Class 3	$71,285	$1,224,604	$340,745	$1,636,634
Class 4	$361	$7,227	$2,249	$9,837
Subtotal	**$76,004**	**$1,279,590**	**$351,518**	**$1,707,112**
Total				
Class 1	$17,296	$56,015	$4,738	$78,049
Class 2	$7,547	$48,445	$4,082	$60,074
Class 3	$162,445	$1,494,773	$409,773	$2,066,990
Class 4	$420	$7,227	$2,292	$9,939
Grand Total	**$187,708**	**$1,606,460**	**$420,884**	**$2,215,052**

ILI = inline inspection
HCA = high consequence area
MAOP = maximum allowable operating pressure
PT = pressure test
SMYS = specified minimum yield strength

Baseline HCA Assessment Costs

Baseline costs for integrity management assessments of HCA segments can be estimated based on historical assessment rates and the unit costs described in this section. In addition to the test methods detailed previously, operators are currently permitted to use direct assessment methods.

Direct assessment (DA), or external corrosion direct assessment (ECDA), involves four distinct phases:

1. Pre-assessment data collection and analysis
2. Indirect inspection by walking along the top of the pipeline, inducing an electrical charge or signal in the steel pipe, and measuring the resulting signal
3. Excavation and direct examination of suspect locations identified by the indirect inspection
4. Post-assessment analysis of inspection and examination findings.

In the first phase, an operator must begin by integrating the historical knowledge of the pipeline, including facilities information, operating history, and the results of prior aboveground indirect examinations and direct examinations of the pipe, to assess the integrity of the pipe. In the second phase, the operator uses the primary and complementary indirect examinations to detect coating defects. The operator uses the results to find coating faults (damaged pipeline coating). For example, based on pipeline history, the operator may use the survey results to determine which coating faults are most likely to correspond to the severely corroded areas. Those areas where the potential for severe corrosion is highest should receive excavation priority. The third phase requires excavations to expose the pipe surface for metal-loss measurements, estimated corrosion growth rates, and measurements of corrosion morphology estimated during indirect examination. The goal of these excavations is to collect enough information to characterize the corrosion defects that may be present on the pipeline segment being assessed and validate the indirect examination methods. The operator should then determine the severity of all corrosion defects at the excavated coating fault areas using ASME B31G or a similar method to determine the safe operating pressure at the location. The final phase sets re-inspection intervals, provides a validation check on the overall ECDA process, and provides performance measures for integrity management programs. The re-inspection interval is a function of the validation and repair activity.

There is a potential range of cost associated with each phase. Cost is largely dependent on location, since the high cost of DA in urban and suburban areas includes traffic control and excavation permitting. PHMSA used BPJ to estimate the cost of each phase (**Table 3-21**) and used the mid estimate.[25] Unlike ILI or pressure testing, unit costs of performing DA are relatively independent of the length of the assessment segment.

Table 3-21 Estimated Unit Cost of Direct Assessment ($ per mile)

Phase	Low Estimate	Mid Estimate	High Estimate
Pre-assessment	$5,000	$7,500	$10,000
Indirect inspection	$2,500	$10,250	$18,000
Direct examination	$15,000	$17,500	$20,000

[25] "Rural Onshore Hazardous Liquid Low Stress Pipelines (Phase II)", Volume II, Jack Faucett & Associates, January, 2011

Table 3-21 Estimated Unit Cost of Direct Assessment ($ per mile)			
Phase	**Low Estimate**	**Mid Estimate**	**High Estimate**
Post-assessment	$5,000	$7,500	$10,000
Total	**$27,500**	**$42,750**	**$58,000**
Source: PHMSA best professional judgment			

Operators have used "other technology" to assess a relatively small amount of mileage. Although not required to report on the specific assessment method used, operators are required to submit notification to PHMSA prior to using other technology for assessments in HCAs. PHMSA reviewed 96 such notifications submitted by operators from 2004 through 2010; all related to the use or application of guided wave ultrasonic testing (GWUT). GWUT is used in special situations, such as at crossings where DA is difficult or problematic, and is often used to supplement a direct assessment. GWUT is similar to DA as it involves indirectly testing pipe to determine if further excavation and direct examination is needed. Like DA, a minimum of one or two excavations is required. Absent specific information about specific methods used, PHMSA assumed the unit costs for other assessments are similar to DA.

Operators report miles of integrity assessments in their annual report submissions. PHMSA summarized this data from 2010-2014 to estimate the proportion of periodic assessments using each methodology (**Table 3-22**).

Table 3-22. Integrity Assessment Methods			
Location	**Inline Inspection**	**Pressure Test**	**Direct Assessment and Other Methods**
Interstate	94%	5%	1%
Intrastate	56%	10%	34%
Source: 2010-2014 PHMSA Annual Report part F.			

As shown in Table 3-2, PHMSA estimated that 432 HCA miles will be tested on interstate pipeline miles and 476 will be tested on intrastate segments. **Table 3-23** shows the results of multiplying by the baseline integrity assessment method rates shown in Table 3-22.

Table 3-23. Estimated Annual Baseline Assessments of HCA Segments Operating at Greater than 30% SMYS				
Location	**Total HCA**	**ILI Miles**	**PT Miles**	**DA and Other Miles**
Interstate	28.8	27.2	1.3	0.3
Intrastate	31.8	17.8	3.2	10.8
HCA = high consequence area SMYS = specified minimum yield strength Source: Total mileage from Table 3-2 divided by 15 and multiplied by rates shown in Table 3-22.				

Table 3-24 shows the results of multiplying the mileage by the assessment unit costs.

Table 3-24. Estimated Baseline Costs Per Year on Previously Untested HCA Segments Operating at Greater than 30% SMYS				
Annual Cost	**Inline Inspections**	**Pressure Tests**	**Direct Assessment and**	**Total**

			Other Methods	
Interstate	$117,546	$297,063	$13,901	$428,511
Intrastate	$81,692	$643,795	$462,339	$1,187,826
Total	$199,239	$940,858	$476,239	$1,616,336

Net Annual Costs

The incremental costs of the proposed rule are the compliance costs net of baseline assessment costs (**Table 3-25)**.

Table 3-25. Net Average Annual Costs to Assess Previously Untested HCA Segments Operating at Greater than 30% SMYS

Component	Interstate	Intrastate	Total
Compliance costs	$507,940	$1,707,112	$2,215,052
Baseline integrity management costs	-$428,511	-$1,187,826	-$1,616,336
Net costs	**$79,430**	**$519,286**	**$598,716**

HCA = high consequence area
SMYS = specified minimum yield strength

3.1.5 ESTIMATION OF COMPLIANCE COSTS TO RE-ESTABLISH MAOP: INADEQUATE RECORDS

Topic Area 1 addresses the statutory requirement in the Act §23(c) which requires that PHMSA issue regulations for the operator to reconfirm MAOP for pipelines for which they do not have records substantiating the material properties of the pipe and the MAOP. Operator annual reports identify significant portions of gas transmission pipeline segments for which they do not have these records.

The Act requires that PHMSA require that MAOP be re-established as expeditiously as economically feasible; and determine what actions are appropriate for the pipeline owner or operator to take to maintain safety until a maximum allowable operating pressure is confirmed. Re-verification of MAOP in most cases would require an integrity assessment that meets specific requirements or equivalent. The assessment and testing requirements to re-establish MAOP are the same that apply to pipe that has not been previously tested (Section 3.1.4).

PHMSA used the following steps to estimate costs:

1. Estimate the mileage of pipe segments for which adequate documentation is lacking.
2. Estimate the breakdown of assessment methods.
3. Estimate the unit costs for conducting the assessments.
4. Estimate total incremental compliance cost.

3.1.5.1 Estimation of Mileage of Pipe for which Records are Inadequate

The proposed rule applies to pipe segments in HCAs and Class 3 and 4 locations. Operators report this data via annual reports required under Part 191. PHMSA used the mileage of pipeline segments (as reported by operators) for which there are not adequate records to support the existing MAOP previously established in accordance with 192.619. The resulting estimate of pipe to which this mandate would apply is shown in **Table 3-26**.

Table 3-26. Mileage of Pipe for which Records are Inadequate

Location	HCA	Class 3 and Class 4 Non-HCA	Total
Interstate			
Class 1	79	0	79
Class 2	97	0	97
Class 3	437	672	1,109
Class 4	1	0.2	1
Subtotal	613	673	1,286
Intrastate			
Class 1	32	0	32
Class 2	34	0	34
Class 3	1,044	1,841	2,886
Class 4	125	1	126
Subtotal	1,235	1,843	3,077
Total			
Class 1	111	0	111
Class 2	130	0	130
Class 3	1,481	2,514	3,995
Class 4	125	2	127
Grand Total	**1,848**	**2,515**	**4,363**

HCA = high consequence area
Source: PHMSA 2014 Gas Transmission Annual Report: Part Q Sum of "Incomplete Records" columns by class location and HCA status

3.1.5.2 Estimation of Breakdown of Assessment Methods

PHMSA used the same method to estimate the breakdown of assessment methods as for previously untested pipe (Section 3.1.4.2) with the inclusion of non-HCA segments. Non-HCA segments have different piggability rates than HCA segments (**Table 3-27**), which therefore influences the assessment method mix. PHMSA assumed that the pressure test rates remain the same.

Table 3-27. Non-HCA Assessment Methods

Class Location	% ILI	Pressure Test	ILI Upgrade
Interstate			
Class 1	71%	5%	24%
Class 2	70%	5%	25%
Class 3	60%	5%	35%
Class 4	56%	0%	44%
Intrastate			
Class 1	53%	10%	37%
Class 2	40%	20%	40%
Class 3	33%	20%	47%

Table 3-27. Non-HCA Assessment Methods			
Class Location	**% ILI**	**Pressure Test**	**ILI Upgrade**
Class 4	62%	21%	17%
Source: Percent assessed with ILI based on 2014 Annual Report submissions on piggability. PHMSA assumed operators will use ILI where possible. Pressure test estimates PHMSA best professional judgment. PHMSA assumed the remainder will be upgraded to accept an ILI tool.			

3.1.5.3 Estimation of Unit Costs

PHMSA used the unit costs for ILI, pressure tests, and upgrading to accommodate ILI tools described in Section 3.1.4.3 for previously untested pipe.

3.1.5.4 Estimation of Total Incremental Cost

Similar to the method described in Section 3.1.4.4, estimation of incremental costs involves estimating total costs to re-establish MAOP, estimating baseline integrity management assessment costs, and subtracting to obtain incremental costs to re-establish MAOP.

Total Cost to Re-establish MAOP

To estimate total costs, PHMSA multiplied the estimated mileages by assessment method by the unit cost of assessments using the same method as for previously untested pipe (Section 3.1.4.4). PHMSA applied the assessment method ratios from Table 3-5 to HCA segments and the ratio from Table 3-18 for non-HCA segments. Again, PHMSA assumed that the assessments are equally distributed over the compliance period (i.e., 1/15th each year for 15 years). **Table 3-28** presents the results.

Table 3-28. Annual Costs to Re-establish MAOP, Segments with Inadequate Records Located in HCAs and Class 3 and 4 Non-HCAs				
Location	**ILI**	**PT**	**Upgrade and ILI**	**Total**
Interstate				
Class 1	$21,604	$59,718	$96	$81,418
Class 2	$26,307	$73,109	$1,158	$100,575
Class 3	$226,920	$839,240	$799,575	$1,865,734
Class 4	$216	$0	$363	$579
Subtotal	$275,047	$972,067	$801,192	$2,048,306
Intrastate				
Class 1	$6,331	$43,666	$14,889	$64,885
Class 2	$6,362	$91,356	$10,337	$108,055
Class 3	$341,079	$7,831,769	$3,373,390	$11,546,239
Class 4	$18,001	$359,107	$111,226	$488,334
Subtotal	$371,773	$8,325,898	$3,509,842	$12,207,513
Total				
Class 1	$27,935	$103,383	$14,985	$146,303
Class 2	$32,669	$164,465	$11,495	$208,630
Class 3	$567,999	$8,671,009	$4,172,965	$13,411,973
Class 4	$18,217	$359,107	$111,589	$488,913
Grand Total	**$646,820**	**$9,297,965**	**$4,311,034**	**$14,255,819**

Table 3-28. Annual Costs to Re-establish MAOP, Segments with Inadequate Records Located in HCAs and Class 3 and 4 Non-HCAs				
Location	**ILI**	**PT**	**Upgrade and ILI**	**Total**
ILI = inline inspection HCA = high consequence area MAOP = maximum allowable operating pressure PT = pressure test SMYS = specified minimum yield strength				

Baseline HCA Assessment Costs

Table 3-29 shows the results of multiplying by the assessment mileage by the baseline integrity assessment method rates.

Table 3-29. Estimated miles of HCA Segments with Inadequate MAOP Records Assessed per Year by Baseline Assessment Method				
Miles	**Total HCA**	**ILI Miles**	**PT Miles**	**DA and Other Miles**
Interstate	40.9	38.6	1.9	0.5
Intrastate	82.3	46.1	8.2	28.0
Source: HCA miles from Table 3-26 divided by 15 years and multiplied by the HCA assessment rates in Table 3-22.				

Table 3-30 shows the results of multiplying the mileage by the assessment unit costs.

Table 3-30. Estimated Annual Costs for Baseline Assessments of HCA Segments: Inadequate Records				
Location	**Inline Inspections**	**Pressure Tests**	**Direct Assessment and Other Methods**	**Total**
Interstate	$166,772	$421,466	$19,722	$607,959
Intrastate	$211,725	$1,668,550	$1,198,262	$3,078,537
Total	$378,497	$2,090,016	$1,217,984	$3,686,497

Net Annual Costs

The incremental costs of the proposed rule are the compliance costs net of baseline assessment costs (**Table 3-31**).

Table 3-31. Net Average Annual Costs to Assess HCA Segments: Inadequate Records			
Component	**Interstate**	**Intrastate**	**Total**
Compliance costs	$2,048,306	$12,207,513	$14,255,819
Baseline integrity management costs	-$607,959	-$3,078,537	-$3,686,497
Net costs	**$1,440,347**	**$9,128,976**	**$10,569,322**

3.1.6 ESTIMATION OF COMPLIANCE COSTS OF INTEGRITY ASSESSMENT FOR SEGMENTS OUTSIDE HCAS

PHMSA is proposing to require integrity assessments of pipeline in Class 3 and 4 MCAs and piggable pipelines in Class 1 and 2 MCAs within 15 years, and every 20 years thereafter. The proposed criteria for determining MCA locations would use the same process and the same definitions as currently used to identify HCAs, except that the threshold for buildings intended for human occupancy and the threshold for persons that occupy other defined sites, that are located within the potential impact radius, would both be lowered from 20 to 5. The intention is that any pipeline location at which five or more houses or persons are normally expected to be located would be afforded extra safety protections.

In addition, as a result of the Sissonville, West Virginia incident, NTSB issued recommendation P-14-01, to revise the gas regulations to add principal arterial roadways including interstates, other freeways and expressways, and other principal arterial roadways as defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures to the list of "identified sites" that establish a high consequence area. PHMSA proposes to meet the intent of NTSB's recommendation by incorporating designated interstates, freeways, expressways, and other principal four-lane arterial roadways into the MCA definition. The Sissonville, West Virginia incident location would not meet the current definition of an HCA, but would meet the proposed definition of an MCA.

Because significant non-HCA pipeline mileage has been previously assessed in conjunction with an assessment of HCA segments in the same pipeline, PHMSA also proposes to allow the use of those prior assessments for non-HCA segments provided that the assessment was conducted in conjunction with an integrity assessment required by subpart O. The proposed rule would also require that the assessment be conducted using the same methods as proposed for HCAs.

PHMSA used the following steps to estimate the cost of performing integrity assessments on select pipelines outside of HCAs:

1. Estimate the mileage of pipe subject to the proposed rule.
2. Estimate the mileage of applicable pipe not previously assessed.
3. Estimate the breakdown of assessment methods.
4. Estimate the unit costs of each assessment method.
5. Estimate total incremental compliance costs.

3.1.6.1 Estimation of Mileage of Pipe Subject to Proposed Rule

PHMSA has reliable information about pipeline mileage in class locations but does not have data on the pipeline mileage that would meet the MCA definition. PHMSA developed an estimate of the mileage that would meet the five home or occupied site criterion using annual report data and BPJ. Specifically, PHMSA used annual report data on mileage outside of HCAs and assumed that approximately 2% of Class 1, 50% of Class 2, and all Class 3 and 4 non-HCA mileage would meet the five home or occupied site MCA criteria. To the extent that this judgment over or understates applicable mileage, costs and benefits will be over or understated. There will be uncertainty regarding this factor until operators identify and report MCA mileage not previously assessed.

PHMSA used National Pipeline Mapping System data overlaid with Federal Highway Administration roadway maps to estimate the additional mileage in Class 1 and Class 2 locations that may overlap with interstates, freeways, expressways, and other principal four-lane arterial roadways. PHMSA estimated the PIR for this analysis based on the diameter of pipe. Diameter is optionally reported on NPMS submissions. For this analysis, PHMSA applied an estimate of PIR based on diameter ranging from 150'-1000'. For unreported segment diameters, PHMSA used the highest PIR estimate. Based on this analysis, for illustration, PHMSA included 20% (2,240 miles out of 11,200 miles) as an estimate of the overlay mileage that would not already meet one of the other criteria for MCA or be located in an HCA. A sensitivity analysis provides a higher bound estimate. PHMSA invites comments on its estimate of mileage affected solely because of proximity to a highway.

Table 3-32 shows the resulting estimate of MCA mileage.

Table 3-32. Estimated MCA Mileage

	Onshore GT Miles[1]	Non-HCA[1,2]	MCA % of Non-HCA[3]	MCA Miles[4]	Roadway MCA Miles[5]	Total MCA Miles[6]
Interstate						
Class 1	160,381	159,374	2%	3,187	1,372	4,559
Class 2	17,811	16,774	50%	8,387	144	8,531
Class 3	13,925	7,378	100%	7,378	0	7,378
Class 4	29	10	100%	10	0	10
Subtotal	192,146	183,535	NA	18,962	1,516	20,478
Intrastate						
Class 1	72,254	71,692	2%	1,434	617	2,051
Class 2	12,820	12,396	50%	6,198	107	6,305
Class 3	19,726	10,224	100%	10,224	0	10,224
Class 4	880	156	100%	156	0	156
Subtotal	105,680	94,468	NA	18,011	724	18,735
Total						
Class 1	232,635	231,066	2%	4,621	1,989	6,610
Class 2	30,631	29,170	50%	14,585	251	14,836
Class 3	33,652	17,601	100%	17,601	0	17,601
Class 4	908	166	100%	166	0	166
Grand Total	**297,826**	**278,003**	**NA**	**36,973**	**2,240**	**39,213**

HCA = high consequence area
MCA = moderate consequence area
1. Source: PHMSA 2014 Gas Transmission Annual Report, Part Q. Total mileage shown for context only.
2. Excludes mileage reported under inadequate maximum allowable operating pressure records.
3. Source: PHMSA best professional judgment; based on homes and occupied sites in primary impact radius only.
4. Non-HCA mileage multiplied by percentage MCA.
5. 20% of total intersecting mileage. Total mileage based on overlay of Federal Highway Administration map with National Pipeline Mapping System pipeline data; 20% based on PHMSA best professional judgment.
6. MCA miles plus additional roadway MCA miles.

3.1.6.2 Estimation of Mileage Not Previously Assessed

The proposed rule would allow operators to use integrity assessments conducted for non-HCA pipe during the course of conducting HCA assessments to demonstrate compliance. Based on the overall reported assessed mileage and assessed mileage in HCAs, PHMSA assumed that 90 percent of non-HCA pipe in Class 4 locations has been assessed in this manner. Similarly, PHMSA assumed that 80 percent of MCA segments in Class 3 locations, 70 percent in Class 2 locations, and 50 percent in Class 1 locations have been assessed in conjunction with HCA assessments.

PHMSA assumed that all pipelines in MCAs that have previously been assessed in conjunction with an HCA assessment would be assessed again in the future within the proposed 15-year compliance period (in conjunction with the next HCA reassessment) for conducting an initial assessment and therefore there would not be a cost from the initial assessment requirement. Estimated MCA mileage not previously assessed would require initial assessment in accordance with proposed § 192.710. MCA segments located in Class 1 and Class 2 will only be subject to the assessment requirements if they are capable of accepting an ILI tool. **Table 3-33** summarizes the estimated incremental impact. Table 3-33 does not include overlap with previously estimated IVP requirements which would comply with integrity assessment requirements (see Section 3.1.7 below). Additionally, due to the location of launchers and receivers, operators may need to run the tools (pigs) for inline inspections through mileage that they are not required to assess (see Section 3.1.8 for a sensitivity analysis of this potential impact).

Table 3-33. Estimation of MCA Mileage Subject to Integrity Assessment Requirements

Location	MCA Mileage[1]	% Piggable[2]	Mileage Subject to Rule[3]	Mileage Subject to Rule less Overlap[4]	% MCA Currently Assessed[5]	MCA not Previously Assessed[6]
Interstate						
Class 1	4,559	72%	3,296	2,666	50%	1,333
Class 2	8,531	70%	5,935	5,397	70%	1,619
Class 3	7,378	NA	7,378	6,489	80%	1,298
Class 4	10	NA	10	10	90%	1
Subtotal	20,478	NA	16,619	14,562	NA	4,251
Intrastate						
Class 1	2,051	53%	1,086	1,009	50%	505
Class 2	6,305	40%	2,507	2,360	70%	708
Class 3	10,224	NA	10,224	9,500	80%	1,900
Class 4	156	NA	156	155	90%	15
Subtotal	18,735	NA	13,972	13,024	NA	3,128
Total						
Class 1	6,610	66%	4,382	3,676	50%	1,838
Class 2	14,836	57%	8,442	7,756	70%	2,327
Class 3	17,601	NA	17,601	15,990	80%	3,198
Class 4	166	NA	166	165	90%	16
Grand Total	**39,213**	**NA**	**30,591**	**27,587**	**NA**	**7,379**

MCA = moderate consequence area
1. See Table 3-24.
2. Assumed equal to non-HCA percent piggable based on data from Part R of the annual report (see Table 3-3).
3. MCA mileage times percent piggable.
4. Excludes MCA mileage subject to MAOP verification provisions
5. Assumed based on the overall reported assessed mileage and assessed mileage in HCAs
6. Mileage subject to proposed rule less overlap with previous other topic areas multiplied by (100%-% not previously assessed).

3.1.6.3 Estimation of Breakdown of Assessment Methods

The proposed rule would also require that the assessment be conducted using the same methods as proposed for HCAs. Because significant non-HCA pipeline mileage has been previously assessed in conjunction with an assessment of HCA segments in the same pipeline, PHMSA also proposes to allow the use of those prior assessments for non-HCA segments to comply with the new § 192.710, provided that the assessment was conducted in conjunction with an integrity assessment required by subpart O.

Using the same process as described in Section 3.1.4.2, PHMSA estimated the assessment methods to be deployed based on historical integrity management assessments (**Table 3-34)**. However, the proposed requirements under §192.710 allow assessments by any of the listed methods. Included in the allowed methods are direct assessment (DA) and other related technology. Direct assessment is not an allowed method for other Topic Area 1 requirements which focus on re-establishing MAOP under §192.624. Because DA is an allowed method, PHMSA assumed that operators would use DA in similar fashion as done to date under integrity management rules for HCAs. As a result of this difference, PHMSA did not assume that operators would upgrade pipelines that are not currently piggable, because DA is an option to assess unpiggable pipelines. **Table 3-35** shows the resulting estimates of mileage by assessment method.

Table 3-34. Estimated MCA Integrity Assessment Methods

Location	ILI[1]	PT[2]	DA and Other Methods[3]
Interstate			
Class 1	100%	0%	0%
Class 2	100%	0%	0%
Class 3	60%	5%	35%
Class 4	55%	5%	40%
Intrastate			
Class 1	100%	0%	0%
Class 2	100%	0%	0%
Class 3	33%	10%	57%
Class 4	62%	10%	28%

1. PHMSA assumed operators will use ILI where possible.
2. 2010-2014 PHMSA Annual Report part F. Historical rates of pressure testing in integrity assessments. The proposed rule requires assessment of pipelines in Class 1 and Class 2 locations only if piggable.
3. PHMSA assumed direct assessment of remaining pipelines.

Table 3-35. Estimated Assessment Methods for MCA Integrity Assessments (Miles)

	ILI	PT	DA & Other	Total
Interstate				
Class 1	1,333	0	0	1,333
Class 2	1,619	0	0	1,619
Class 3	773	59	466	1,298

Table 3-35. Estimated Assessment Methods for MCA Integrity Assessments (Miles)				
	ILI	**PT**	**DA & Other**	**Total**
Class 4	1	0	0	1
Subtotal	3,725	59	467	4,251
Intrastate				
Class 1	505	0	0	505
Class 2	708	0	0	708
Class 3	630	189	1,081	1,900
Class 4	10	2	4	15
Subtotal	1,852	191	1,085	3,128
Total				
Class 1	1,838	0	0	1,838
Class 2	2,327	0	0	2,327
Class 3	1,403	248	1,547	3,198
Class 4	10	2	5	16
Grand Total	**5,578**	**250**	**1,552**	**7,379**

Source: Based on Table 3-25 and Table 3-26.
DA = direct assessment
ILI = inline inspection
MCA = moderate consequence area
PT = pressure test

3.1.6.4 Estimation of Unit Costs

PHMSA used the unit costs for ILI and pressure testing, and direct assessment described above (see Section 3.1.4.3 and 3.1.4.5).

3.1.6.5 Estimation of Total Incremental Cost

Multiplying the estimated annual assessment mileages (total divided by 15 years, assuming that the assessments are equally distributed over the compliance period) by the unit costs results in the expected annual assessment costs. **Table 3-36** summarizes these results.

Table 3-36. Estimated Annual Costs for Expansion of Integrity Assessments Outside of HCAs				
	ILI	**PT**	**DA & Other**	**Total**
Interstate				
Class 1	$384,255	$0	$0	$384,255
Class 2	$466,647	$0	$0	$466,647
Class 3	$222,686	$891,819	$1,329,127	$2,443,632
Class 4	$161	$695	$1,161	$2,016
Subtotal	$1,073,748	$892,514	$1,330,288	$3,296,549
Intrastate				
Class 1	$145,469	$0	$0	$145,469
Class 2	$204,061	$0	$0	$204,061
Class 3	$181,620	$2,567,796	$3,080,114	$5,829,530

Table 3-36. Estimated Annual Costs for Expansion of Integrity Assessments Outside of HCAs				
	ILI	PT	DA & Other	Total
Class 4	$2,772	$20,892	$12,266	$35,929
Subtotal	$533,922	$2,588,687	$3,092,380	$6,214,989
Total				
Class 1	$529,723	$0	$0	$529,723
Class 2	$670,708	$0	$0	$670,708
Class 3	$404,306	$3,459,615	$4,409,241	$8,273,162
Class 4	$2,932	$21,586	$13,427	$37,946
Grand Total	**$1,607,669**	**$3,481,201**	**$4,422,668**	**$9,511,538**

DA = direct assessment
ILI = inline inspection
HCA = high consequence area
PT = pressure test

3.1.7 ESTIMATION OF COMPLIANCE COST TO RE-ESTABLISH MAOP FOR PREVIOUSLY UNTESTED PIPE OTHER THAN HCA GREATER THAN THIRTY PERCENT SMYS

NTSB issued two recommendations to PHMSA related to MAOP verification as a result of its investigation of the San Bruno incident. NTSB recommended that PHMSA amend 49 CFR § 192.619 to delete the exception and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test (Recommendation P-11-14) NTSB also recommended that PHMSA amend 49 CFR Part 192 so that manufacturing-related and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times MAOP (Recommendation P-11-15).

Section 3.1.4 addresses the proposed requirements that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test. In addition, the proposed rule would require re-establishing MAOP for previously untested pipe in the following categories:

- HCA operating at greater than 20 percent SMYS (greater than 30 percent SMYS is included above)
- Non-HCA within Class 3 and Class 4 locations
- MCA within Class 1 and Class 2 (piggable lines only).

The cost estimate for this requirement is structured as follows:

- Estimate the population of pipe segments to which the proposed requirements would apply.
- Estimate the breakdown of assessment methods expected to be deployed.
- Estimate the unit costs for each assessment method.
- Estimate total annual costs to achieve compliance by the deadlines specified in the proposed rule.

3.1.7.1 Estimation of Mileage of Previously Untested Pipe

Table 3-37, Table 3-38, and **Table 3-39** provide the estimated mileage of previously untested pipe in these categories. HCA mileage operated at between 20 and 30 percent SMYS is estimated as the total HCA mileage of previously untested pipe multiplied by the percent of mileage that operates between 20 and 30 percent of SMYS. Previously untested pipe outside of HCAs within Class 3 and 4 locations is reported by operators. Piggable previously untested MCA mileage in Class 1 and 2 locations is estimated by multiplying the estimated piggable MCA mileage by the percent of non-HCA mileage previously untested as reported by operators.

Table 3-37. Estimated Mileage of Previously Untested Pipe Operating at 20-30% SMYS in HCAs

Location	Previously Untested HCA Miles[1]	Percent of all Pipe Operating at 20-30% SMYS[1]	HCA Miles 20-30% SMYS[2]
Interstate			
Class 1	62	5%	3
Class 2	23	8%	2
Class 3	439	9%	41
Class 4	0	32%	0
Subtotal	524	NA	46
Intrastate			
Class 1	13	11%	1
Class 2	18	21%	4
Class 3	749	28%	213
Class 4	5	49%	3
Subtotal	786	NA	221
Total			
Class 1	75	7%	5
Class 2	41	14%	6
Class 3	1,189	21%	244
Class 4	6	48%	3
Grand Total	**1,310**	**NA**	**267**

HCA = high consequence area
SMYS = specified minimum yield strength
1. Source: 2014 PHMSA Gas Transmission Annual Report
2. Calculated as untested HCA mileage times percent of all pipe operated at 20-30% SMYS.

Table 3-38. Previously Untested Non-HCA Pipe in Class 3 and 4 Locations

Location	Mileage
Interstate	
Class 3	888
Class 4	0
Subtotal	888
Intrastate	

Table 3-38. Previously Untested Non-HCA Pipe in Class 3 and 4 Locations

Location	Mileage
Class 3	724
Class 4	1
Subtotal	725
Total	
Class 3	1,612
Class 4	1
Grand Total	**1,613**
Source: 2014 PHMSA Gas Transmission Annual Report.	

Table 3-39. Estimation of Piggable MCA Mileage in Class 1 and 2 Locations

Location	Piggable MCA[1]	Percent of Non-HCA Mileage Previously Untested[2]	Previously Untested Piggable MCA Mileage[3]
Interstate			
Class 1	3,296	19%	630
Class 2	5,935	9%	538
Subtotal	16,619	NA	1,168
Intrastate			
Class 1	1,086	7%	76
Class 2	2,507	6%	147
Subtotal	3,593	NA	223
Total			
Class 1	4,382		706
Class 2	8,442	NA	686
Grand Total	**12,824**	**NA**	**1,392**

MCA = moderate consequence area
1. Estimated as MCA (Table 3-24) times % piggable non-HCA (Table 3-3).
2. Source: 2014 PHMSA Gas Transmission Annual Report.
3. Calculated as piggable MCA mileage multiplied by percent untested non-HCA mileage.

Table 3-40 summarizes these mileages.

Table 3-40. Summary of Applicable Previously Untested Mileage

Location	HCA Operating at 20-30% SMYS	Class 3 and 4 Non-HCA	Piggable Class 1 and 2 MCA	Total
Interstate				
Class 1	3	0	630	633
Class 2	2	0	538	540
Class 3	41	888	0	929
Class 4	0	0	0	0
Subtotal	46	888	1,168	2,103
Intrastate				
Class 1	1	0	76	78
Class 2	4	0	147	151

Table 3-40. Summary of Applicable Previously Untested Mileage				
Location	HCA Operating at 20-30% SMYS	Class 3 and 4 Non-HCA	Piggable Class 1 and 2 MCA	Total
Class 3	213	724	0	937
Class 4	3	1	0	4
Subtotal	221	725	223	1,169
Total				
Class 1	5	0	706	711
Class 2	6	0	686	691
Class 3	254	1,612	0	1,866
Class 4	3	1	0	4
Grand Total	**267**	**1,613**	**1,392**	**3,272**

Source: See Tables 3-30, 3-31, and 3-32.
HCA = high consequence area
MCA = moderate consequence area
SMYS = specified minimum yield strength

3.1.7.2 Estimation of Breakdown of Assessment Methods

For mileage in HCAs operating at greater than 20 percent SMYS and non-HCA within Class 3 and Class 4 locations, PHMSA applied the assessment method ratios described in Section 3.1.6.3 to all non-MCA mileage within this part. For the remainder (piggable pipe in MCA Class 1 and 2 locations), PHMSA assumed 100% of these miles will be inspected via ILI. **Table 3-41** shows the results (see **Appendix A** for details).

Table 3-41. Miles by Estimated Assessment Method				
Location	Total ILI	PT	Upgrade and ILI	Total
Interstate				
Class 1	633	0	0	633
Class 2	540	0	0	540
Class 3	466	38	259	763
Class 4	0	0	0	0
Subtotal	1,639	38	259	1,937
Intrastate				
Class 1	77	0	0	78
Class 2	150	1	1	151
Class 3	261	130	258	649
Class 4	2	1	1	3
Subtotal	490	131	259	880
Total				
Class 1	710	0	0	711
Class 2	690	1	1	691
Class 3	728	168	516	1,412
Class 4	2	1	1	3
Grand Total	**2,129**	**170**	**518**	**2,817**

3.1.7.3 Estimation of Unit Costs

PHMSA used the unit costs as developed in Section 3.1.4.3.

3.1.7.4 Estimation of Total Incremental Cost

Similar to the method described in Section 3.1.4.4, estimation of incremental costs involves estimating total costs to re-establish MAOP, estimating baseline integrity management assessment costs, and subtracting to obtain incremental costs to re-establish MAOP.

Total Cost to Re-establish MAOP

To estimate total costs, PHMSA multiplied the estimated mileages by assessment method by the unit cost of assessments using the same method as for previously untested pipe (Section 3.1.4.4). Multiplying the estimated annual assessment mileages (total divided by 15 years, assuming that the assessments are equally distributed over the compliance period) by the unit costs results in the expected annual assessment costs summarized in **Table 3-42** shows the results.

Table 3-42. Annual Costs to Re-establish MAOP, Previously Untested Segments Other than HCA Operating at Greater than 30% SMYS

Location	ILI	PT	Upgrade and ILI	Total
Interstate				
Class 1	$182,419	$2,317	$4	$184,740
Class 2	$155,703	$1,381	$22	$157,106
Class 3	$134,370	$577,245	$775,775	$1,487,390
Class 4	$35	$0	$25	$60
Subtotal	$472,527	$580,943	$775,826	$1,829,296
Intrastate				
Class 1	$22,249	$2,015	$687	$24,952
Class 2	$43,135	$10,339	$1,170	$54,644
Class 3	$75,330	$1,760,636	$772,369	$2,608,335
Class 4	$450	$8,626	$2,489	$11,565
Subtotal	$141,165	$1,781,616	$776,715	$2,699,495
Total				
Class 1	$204,669	$4,332	$691	$209,692
Class 2	$198,838	$11,720	$1,192	$211,749
Class 3	$209,700	$2,337,880	$1,548,144	$4,095,725
Class 4	$485	$8,626	$2,514	$11,625
Grand Total	**$613,692**	**$2,362,558**	**$1,552,541**	**$4,528,791**

ILI = inline inspection
HCA = high consequence area
MAOP = maximum allowable operating pressure
PT = pressure test
SMYS = specified minimum yield strength

Baseline High Consequence Area Assessment Costs

Table 3-x shows the results of multiplying by the assessment mileage by the baseline

integrity assessment method rates.

Table 3-43. Estimated Miles of Previously Untested HCA Segments Operating at 20%-30% SMYS Assessed per Year by Baseline Assessment Method				
Location	**Total HCA**	**Inline Inspection**	**Pressure Test**	**Direct Assessment and Other Methods**
Interstate	3.1	2.9	0.1	0.03
Intrastate	14.7	8.2	1.5	5.0
HCA = high consequence area SMYS = specified minimum yield strength Source: HCA mileage from Table 3-30 divided by 15 and multiplied by the baseline HCA assessment rates from Table 3-22				

PHMSA multiplies this mileage by the assessment unit costs to estimate the cost to complete HCA baseline integrity management assessments on HCA mileage in this section **(Table 3-44).**

Table 3-44.Estimated Baseline Costs Per Year on HCA Segments Operating at 20%-30% SMYS Assessed per Year by Baseline Assessment Method				
Location	**Inline Inspections**	**Pressure Tests**	**Direct Assessment and Other Methods**	**Total**
Interstate	$12,558	$31,736	$1,485	$45,779
Intrastate	$37,889	$298,598	$214,437	$550,924
Total	**$50,447**	**$330,334**	**$215,922**	**$596,703**

Net Annual Costs

The incremental costs of the proposed rule are the compliance costs net of baseline assessment costs (**Table 3-45)**.

Table 3-45. Net Average Annual Costs to Assess HCA Segments Operating at 20-30% Specified Minimum Yield Strength			
Component	**Interstate**	**Intrastate**	**Total**
Compliance costs	$1,829,296	$2,699,495	$4,528,791
Baseline integrity management costs	-$45,779	-$550,924	-$596,703
Net costs	**$1,783,517**	**$2,148,571**	**$3,932,088**

3.1.8 SOCIAL COST OF METHANE DUE TO BLOWDOWN EMISSIONS

As noted above**Error! Reference source not found.**, upgrading pipelines to accommodate ILI and pressure testing pipelines will entail the release of natural gas into the atmosphere via a blowdown procedure. Natural gas is comprised primarily of methane (**Table 3-46**), a potent GHG. PHMSA used estimates of the social cost of methane (SCM) that were developed by Marten et al., (2014) to value these emissions. See Appendix B for discussion and annual values.

Table 3-46. Natural Gas Composition	
Gas	**Percent of Volume**
Methane (CH_4)	95.7%

Table 3-46. Natural Gas Composition	
Gas	**Percent of Volume**
Carbon dioxide ($C0_2$)	1.3%
Other Fluids	3.0%
Source: Estimated based on natural gas quality standards and operator reported measurements Enbridge Estimates: https://www.enbridgegas.com/gas-safety/about-natural-gas/components-natural-gas.aspx Spectra Estimates: https://www.uniongas.com/about-us/about-natural-gas/Chemical-Composition-of-Natural-Gas	

3.1.8.1 Emissions from Pressure Testing

Pressure testing will involve emptying the segment of natural gas. PHMSA used annual report data on gas transmission pipeline diameter (**Table 3-47**) and estimates of natural gas emissions per mile due to pressure test blowdowns by segment diameter (**Table 3-48**) to calculate a weighted average estimate of emissions per mile for pressure tests in interstate and intrastate segments. **Table 3-49** presents these greenhouse gas emissions per mile.

Table 3-47. Proportion of Gas Transmission Mileage by Diameter			
Segment Type	**<12" Diameter**	**14"-34" Diameter**	**36"+ Diameter**
Interstate	27%	57%	15%
Intrastate	57%	37%	6%
Source: 2014 Gas Transmission Annual Report			

Table 3-48. GHG Emissions from Pressure Test Blowdowns			
Diameter (inches)	**Gas Released (MCF)**	**Methane (MCF)**	**Carbon Dioxide (lbs)**
12	113	108	168
24	424	406	631
36	974	932	1,449
Source: See Equation 1 and Table 3-46 lbs = pounds MCF = thousand cubic feet			

Table 3-49. GHG Emissions from Pressure Tests per Assessment Mile			
Location	**Gas Released per mile (MCF)**	**Methane Released per Mile (MCF)**	**Carbon Dioxide Released per Mile (lbs)**
Interstate	418	400	622
Intrastate	280	268	416
lbs = pounds MCF = thousand cubic feet 1. Weighted average based on share of pipeline mileage by diameter.			

PHMSA then multiplied these values by the estimates of miles assessed by pressure tests in Section 3.1 to calculate emissions for each subtopic of Topic Area 1. The results are shown in **Table 3-50** below.

Table 3-50. Total GHG Emissions from Pressure Test Blowdowns

Item	PT Miles (Interstate)	PT Miles (Intrastate)	Gas Released (MCF)	Methane (MCF)	Carbon Dioxide (lbs)
Re-establish MAOP: HCA > 30% SMYS	2[1]	47[1]	13,930	13,331	20,717
Re-establish MAOP: Inadequate Records	36[2]	566[2]	173,576	166,112	258,142
Integrity Assessment: Non-HCA	59[1]	191[1]	78,037	74,682	116,057
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	36[1]	109[1]	45,754	43,787	68,045
Total	**134**	**913**	**311,297**	**297,911**	**462,961**

PT = pressure test
MCF = thousand cubic feet
1. Miles pressure tested for compliance with MAOP reverification requirements minus baseline HCA pressure test miles
2. MCA miles pressure tested for compliance with MCA integrity assessment requirements

3.1.8.2 Emissions from ILI Upgrade

Operators will also need to blowdown segments in order to make the necessary upgrades to permit a line to accept an inline inspection tool. Besides the new emissions estimate and a different breakdown of mileage by diameter, the analysis proceeds identically as for the estimate for blowdowns due to pressure testing. **Table 3-51** provides the estimated volume of gas released during ILI upgrades based on Equation 1. **Table 3-52** provides the proportion of gas transmission mileage by diameter, which is used to calculate the weighted average volume of gas released per ILI upgrade mile.

Table 3-51. Natural Gas Lost due to Blowdowns per Mile (MCF/Mile)

Location	Diameter 12" or less	Diameter 14" to 24"	Diameter 26" and above
Interstate	19	78	286
Intrastate	13	52	190

MCF = thousand cubic feet
Source: See Equation 1 in Section 3.1.4.3

Table 3-52. Proportion of Gas Transmission Mileage by Diameter

Segment Type	≤ 12" Diameter	14"-24" Diameter	≥ 26"Diameter
Interstate	27%	32%	41%
Intrastate	57%	29%	14%

Source: 2014 Gas Transmission Annual Reports

Table 3-53 provides the estimate for emissions per mile due to upgrade related blowdowns.

Table 3-53. GHG Emissions from Blowdowns, ILI Upgrade (per Mile)

Location	Gas Released (MCF)[1]	Methane Emissions (MCF)[2]	$C0_2$ Emissions (lbs)[3]
Interstate	147	140	218

Intrastate	49	47	73

CO_2 = carbon dioxide
GHG = greenhouse gas
HCA = high consequence area
ILI = inline inspection
lbs = pounds
MCF = thousand cubic feet
1. Weighted average based on natural gas emissions due to upgrade by diameter and annual report diameter data.
2. Gas emissions multiplied by 95.7% methane.
3. Gas emissions multiplied by 1.3% $C0_2$ and 114.4 lbs/MCF $C0_2$.

Table 3-54 summarizes total greenhouse gas emissions due to blowdowns for ILI upgrade are summarized in

Table 3-54. Total GHG Emissions due to Blowdowns

Item	ILI Upgrade Miles (Interstate)	ILI Upgrade Miles (Intrastate)	Gas Released (MCF)	Methane Emissions (MCF CH_4)	$C0_2$ Emissions (lbs)
Re-establish MAOP: HCA > 30% SMYS	23	118	42,817	40,975	63,677
Re-establish MAOP: Inadequate Records	267	1,174	440,285	421,353	654,792
Integrity Assessment: Non-HCA	0	0	0	0	0
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	259	259	180,781	173,008	268,858
Total	**549**	**1,552**	**663,883**	**635,336**	**987,327**

CO_2 = carbon dioxide
CH_4 = methane
GHG = greenhouse gas
HCA = high consequence area
ILI = inline inspection
MAOP = maximum allowable operating pressure
MCF = thousand cubic feet
SMYS = specified minimum yield strength

3.1.8.3 Total Emissions

PHMSA assumed that the assessment rate is the same for each year of the assessment period. Therefore, emissions per year are calculated as the total divided by 15 (**Table 3-55**).

Table 3-55. Total Emissions Per Year

Item	Gas Released (MCF)	Methane Emissions (MCF CH_4)	$C0_2$ Emissions (lbs)
Re-establish MAOP: HCA > 30% SMYS	3,783	3,620	5,626
Re-establish MAOP: Inadequate Records	40,924	39,164	60,862
Integrity Assessment: Non-HCA	5,202	4,979	7,737

Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	15,102	14,453	22,460
Total	**65,012**	**62,216**	**96,686**
CO_2 = carbon dioxide CH_4 = methane HCA = high consequence area lbs = pounds MAOP = maximum allowable operating pressure MCF = thousand cubic feet SMYS = specified minimum yield strength			

3.1.8.4 Summary of Estimated Environmental Costs

PHMSA used the estimates of SCM described in Appendix B to value the costs associated with the estimated emissions. **Table 3-56** shows these results.

Table 3-56. Average Annual Social Cost of Gas Lost due to Blowdown (Millions 2015$)

Topic Area 1 Scope	Average Annual Methane Lost from Blowdown (MCF)			Average Annual Social Cost [1]
	ILI Upgrade	Pressure Test	Total	
Previously untested in HCA	2,854	929	3,620	$0.11
HCA and Class 3 and 4 with inadequate records	29,352	11,572	39,164	$1.15
Applicable MCA	0	5,202	4,979	$0.15
Previously other HCA and non-HCA	12,052	3,050	14,453	$0.43
Subtotal	44,259	20,753	62,216	$1.83

MCF = thousand cubic feet
1. Based on the values for social cost of methane and social cost of carbon calculated using a 3% discount rate (see Appendix B).

3.1.9 SUMMARY AND SENSITIVITY ANALYSES

Table 3-57 provides the present value of costs over the study period for Topic Area 1.

Table 3-57. Present Value Costs Discounted at 7%, Topic Area 1 (Millions 2015$)[1]

Scope	Total			Average Annual		
	Compliance Cost	Social Cost of GHG Emissions	Total Cost	Annual Compliance Cost	Annual Social Cost of GHG Emissions	Average Annual Cost
Re-establish MAOP: HCA > 30% SMYS	$5.8	$1.6	$7.4	$0.4	$0.1	$0.5
Re-establish MAOP: Inadequate Records	$103.0	$17.3	$120.3	$6.9	$1.2	$8.0
Integrity Assessment: Non-HCA	$92.7	$2.2	$94.9	$6.2	$0.1	$6.3

Table 3-57. Present Value Costs Discounted at 7%, Topic Area 1 (Millions 2015$)[1]						
Scope	**Total**			**Average Annual**		
	Compliance Cost	**Social Cost of GHG Emissions**	**Total Cost**	**Annual Compliance Cost**	**Annual Social Cost of GHG Emissions**	**Average Annual Cost**
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	$38.3	$6.4	$44.7	$2.6	$0.4	$3.0
Total	**$239.9**	**$27.5**	**$267.3**	**$16.0**	**$1.8**	**$17.8**

GHG = greenhouse gas
HCA = high consequence area
MAOP = maximum allowable operating pressure
SMYS = specific minimum yield strength
1. Total is of the 15 year compliance period; average annual is total divided by 15.

Table 3-58. Present Value Costs Discounted at 3%, Topic Area 1 (Millions 2015$)[1]						
Scope	**Total**			**Average Annual**		
	Compliance	**Social Cost of GHG Emissions**	**Total**	**Compliance**	**Social Cost of GHG Emissions**	**Total**
Re-establish MAOP: HCA > 30% SMYS	$7.4	$1.6	$9.0	$0.5	$0.1	$0.6
Re-establish MAOP: Inadequate Records	$130.0	$17.3	$147.2	$8.7	$1.2	$9.8
Integrity Assessment: Non-HCA	$117.0	$2.2	$119.2	$7.8	$0.1	$7.9
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	$48.3	$6.4	$54.7	$3.2	$0.4	$3.6
Total	**$302.6**	**$27.5**	**$330.1**	**$20.2**	**$1.8**	**$22.0**

HCA = high consequence area
MAOP = maximum allowable operating pressure
SMYS = specific minimum yield strength
1. Total is of the 15 year compliance period; average annual is total divided by 15.

These cost estimates are subject to uncertainty with respect to estimated mileages and the unit costs for integrity assessment methods.

As a practical matter, ILI is conducted in a continuous segment between tool launcher and receiver facilities. Launchers and receivers are already in place, typically located at compressor stations spaced 20 to 50 miles apart, for much of the mileage that will be identified as MCAs under the proposed rule. Some of this has already been assessed as reflected in the analysis. However, PHMSA does not have locational data on previously unassessed pipeline that would be classified as MCA under the proposed rule and the location of launchers and receivers along this pipeline to estimate any additional non-MCA mileage that would be assessed. Therefore, PHMSA did not include costs (or benefits) for assessing additional mileage that is not required to be assessed under the proposed rule.

PHMSA invites comments and data on the extent of such mileage. Absent such data, PHMSA conducted a sensitivity analysis of the estimated costs to additional ILI mileage by applying a factor to all ILI mileage. **Table 3-59** shows the results for a doubling of ILI mileage, which results in an approximately 11percent increase in costs. A tripling of ILI mileage results in an approximately 22 percent increase in costs.

Table 3-59. Present Value Costs, Topic Area 1: ILI Miles Doubled (Millions 2015$)

Scope	7% Discount Rate		3% Discount Rate	
	Total	Average Annual	Total	Average Annual
Re-establish MAOP: HCA > 30% SMYS	$9.3	$0.6	$11.3	$0.8
Re-establish MAOP: Inadequate Records	$126.6	$8.4	$155.2	$10.3
Integrity Assessment: MCA	$110.6	$7.4	$138.9	$9.3
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; MCA Class 1 and 2	$50.7	$3.4	$62.3	$4.2
Total	**$297.1**	**$19.8**	**$367.7**	**$24.5**

HCA = high consequence area
ILI = inline inspection
MAOP = maximum allowable operating pressure
SMYS = specific minimum yield strength

Occasionally operators will have to provide alternative gas supplies during pressure tests if the line is the sole source of gas for a community. This situation could influence the cost of completing a pressure test. PHMSA assumed that 10% of pressure tests will require alternative gas supplies If this rate is reduced to zero, present value costs for Topic Area 1 fall 11% ($15.9 million average annual and $ 238.9 million total at a 7% discount rate; $19.6 million average annual and $294.3million total at a 3% discount rate). Note that these additional assessments would also result in benefit associated with averting incidents (safety and GHG emission reductions).

Another source of uncertainty is the extent to which gas transmission pipeline PIRs overlap with highway right-of-ways. Section 3.1.6 uses an illustration of 20% of such mileage not meeting other MCA or HCA criteria. PHMSA calculated a highest cost estimate assuming that 89% of pipeline mileage conflicting with highway right-of-way (9,912 miles). This percentage is equivalent to the percent of all gas transmission miles located in Class 1 and Class 2 locations. In this scenario, annual average present value compliance costs using a 7 percent discount rate would rise from $17.8 to $18.3 million, an increase of approximately 3% ($22.0 to $22.7 million using a 3 percent discount rate). Benefits would likely rise proportionally, however the overall impact of this assumption is small.

An additional alternative for highway mileage costs would be to calculate a weighted average of pipeline-highway overlap mileage for the unreported diameters based on rates for the reported diameter segments rather than conservatively applying the highest PIR estimates. Using this method the total overlap mileage falls from 11,200 to approximately 8,400, reducing mileage by 25%. Compared to the 20% scenario in the base analysis, this change causes average annual present value costs to fall by less than $50,000 a year in either the 7% or 3% discount rate scenarios.

3.2 INTEGRITY MANAGEMENT PROGRAM (IMP) PROCESS CLARIFICATIONS

Topic Area 2 includes the following clarifications to the IM regulations in 49 CFR Part 192, Subpart O:

1. Clarify management of change (MoC) process requirements for operator IM programs [§ 192.911]
2. Clarify threat identification requirements for time-dependent threats [§ 192.917]
3. Clarify requirements related to baseline assessment methods [§ 192.921]
4. Clarify (and in limited cases, revise) repair criteria for remediating defects discovered in HCA segments
5. Clarify preventive and mitigative (P&M) measures based on risk assessments, to include more examples such as correcting root causes of past incidents [§ 192.935(a)]
6. Clarify P&M measures for covered segments for outside force damage [§ 192.935(b)]
7. Clarify requirements for periodic evaluations and assessments, including some specifically for plastic transmission pipelines [§ 192.937]
8. Written notification for a 6-month extension of 7-yr reassessment interval [§ 192.939]

3.2.1 PROBLEM STATEMENT

Title 49 CFR Part 192, Subpart O prescribes requirements for managing pipeline integrity in defined HCAs. Following the San Bruno incident, the NTSB recommended that PG&E assess every aspect of its IM program, paying particular attention to the areas identified in the incident investigation. PHMSA also analyzed the issues related to information analysis and risk assessment that the NTSB identified in its investigation. PHMSA held a workshop on July 21, 2011 to address perceived shortcomings in the implementation of IM risk assessment processes and the information and data analysis (including records) upon which such risk assessments are based. PHMSA sought input from stakeholders on these issues, and determined that additional clarification and specificity is needed for existing performance-based rules.

The proposed rule clarifies the performance-based risk assessment aspects of the IM rule to specify that operators perform risk assessments that are adequate to:

- Evaluate the effects of interacting threats
- Determine additional preventive and mitigative measures needed
- Analyze how a potential failures could affect HCAs, including the consequences of the entire worst-case incident scenario from initial failure to incident termination
- Identify the contribution to risk of each risk factor, or each unique combination of risk factors that interact or simultaneously contribute to risk at a common location
- Account for, and compensate for, uncertainties in the model and the data used in the risk assessment
- Evaluate risk reduction associated with candidate activities such as preventive and mitigative measures.

The proposed rule would also expand on, and provide more specificity for, conducting integrity assessments and remediating anomalies found as a result of those assessments.

3.2.2 ASSESSMENT OF REGULATORY IMPACT

These clarifications, with a few limited exceptions, would not alter, change or revise the requirements of Subpart O. As such, they would not represent changes that would be expected to result in measurable costs to pipeline operators (with a few exceptions, which are explicitly identified and for which PHMSA performed a cost analysis). The information presented in this section describes the basis for this conclusion for each of the proposed revisions to Subpart O.

<u>Management of Change</u>
49 CFR § 192.911(k) requires that IM programs include a management of change process as outlined in ASME/ANSI B31.8S, Section 11. PHMSA has determined that more specific attributes of the MoC process should be codified within the text of § 192.911(k). The proposed rule would amend § 192.911(k) to specify that the MoC process must include the reasons for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. These attributes are already required by reference to ASME B31.8S as if they were set out in the rule in full (see §192.7(a)). Since these are not new requirements, PHMSA concluded that this requirement would not impose an additional cost burden on pipeline operators.

<u>Threat Identification Requirements</u>
49 CFR § 192.917(b) requires data gathering and integration requirements as part of an effective IM program. Data gathering and integration is an important element of good IM practices. Accordingly, the proposed rule would include specific performance-based requirements for collecting, validating, and integrating pipeline data. These would add specificity to the data integration language, list a number of pipeline attributes that must be included in these analyses, explicitly require that operators integrate analyzed information, and ensure data is verified and validated.

The proposed rule would also require operators to use validated, objective data to the maximum extent practical. To the degree that subjective data from SMEs must be used, PHMSA requires that operator programs include specific features to compensate for SME bias. These attributes are already required by reference to ASME B31.8S, Section 4, as if they were set out in the rule in full (see §192.7(a)).

49 CFR § 192.917(c) requires operators to perform risk assessment as part of an effective IM program. The proposed rule would clarify that operators must perform risk assessments that address worst case scenarios and that are capable of accounting for uncertainties and quantifying risk-reduction alternatives. In addition, in response to NTSB Recommendation P-11-18, the proposed rule would add performance-based language to require that operators validate their risk models in light of incident, leak, and failure history, and other historical information. The proposed rule would also clarify that operators use the risk assessment to establish and implement adequate operations and maintenance processes, and establish and deploy adequate resources for successful execution of activities, processes, and systems associated with operations, maintenance, preventive measures, mitigative measures, and managing pipeline integrity.

In accordance with §§ 192.917(b) and 192.917(c), these attributes of data gathering and integration, and risk assessment, are already required by reference to ASME B31.8S, Sections 4 and 5, as if they were set out in the rule in full (see §192.7(a)). Therefore, this requirement would not impose an additional cost burden on pipeline operators.

<u>Baseline Assessment Methods</u>
49 CFR § 192.921 requires that pipelines subject to IM rules have an integrity assessment. Current rules allow the use of ILI, PT in accordance with 49 CFR Part 192, Subpart J, DA for the threats of external corrosion, internal corrosion, and SCC, and other technology that the operator demonstrates provides an equivalent level of understanding of the condition of the pipeline.

Following the San Bruno incident PHMSA determined that baseline assessment methods should be revised to emphasize ILI and PT over direct assessment. For the failed San Bruno pipeline, PG&E relied heavily on DA under circumstances for which it is not effective. Further, ongoing research and industry response to the ANPRM[26] appears to indicate that stress corrosion cracking direct assessment (SCCDA) is not as effective and does not provide an equivalent understanding of pipe conditions with respect to stress corrosion cracking defects as ILI or hydrostatic pressure testing at test pressures exceeding those required by 49 CFR Part 192, Subpart J (i.e., “spike” hydrostatic pressure test). Therefore, the proposed rule would require that DA only be allowed when the pipeline cannot be assessed using ILI. As a practical matter, DA is typically not chosen as the assessment method if the pipeline can be assessed using ILI. Therefore, this requirement would not impose a significant additional cost burden on pipeline operators.

The proposed rule would also add three assessment methods:

1. A “spike” hydrostatic pressure test, which is particularly well suited to address stress corrosion cracking and other cracking or crack-like defects;

[26] *Ibid*. 4

2. Guided Wave Ultrasonic Testing (GWUT), which is particularly appropriate in cases where short segments such as road or railroad crossings are difficult to assess; and

3. Excavation with direct *in situ* examination.

All of these assessment methods are implicitly allowed by existing requirements; the proposed rule would not mandate use.

GWUT is "other technology" under existing rules, and operators must notify PHMSA prior to its use. PHMSA has developed guidelines for the use of GWUT, which have proven successful, and incorporated them into the proposed rule. As such, future notifications would not be required, representing a cost savings for operators. Therefore, including these additional assessment methods in the proposed rule would not impose an additional cost burden on pipeline operators.

With regard to conducting integrity assessments using ILI, internal corrosion direct assessment (ICDA), or SCCDA, the proposed rule would invoke certain consensus industry standards by reference. When the IM rule was promulgated, industry standards for these assessment methods were still under development. Minimal guidance was provided in ASME B31.8S, incorporated by reference into regulations, but the current rule and ASME B31.8S are generally silent on specific guidance for successfully performing such assessments. Subsequently, NACE International, ASME, and the American Society for Nondestructive Testing (ASNT) have developed consensus industry standards for these assessment methods. These standards have been used successfully since the mid-2000s, and are the best available guidance. Most operators already successfully utilize these standards when conducting these types of assessments. Therefore, incremental cost to operators from incorporating these standards by reference in the pipeline safety regulations would be negligible compared to the cost of the additional scope described in Section 3.2.

The proposed rule expands the performance-based language to clarify that operators must assure that persons qualified by knowledge, training, and experience must analyze the data obtained from an ILI to determine if a condition could adversely affect the safe operation of the pipeline. Operators must also explicitly consider uncertainties in reported results in identifying and characterizing anomalies. This includes, but is not limited to: tool tolerance, detection threshold and probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties, and verifying actual tool performance. Such issues are generally addressed in the ASME standard, either explicitly or implicitly. These requirements are incorporated in §192.921(a) by reference to ASME B31.8S, Section 6.2 as if they were set out in full (see §192.7(a)). Since these are not new requirements, the language change does not impose an additional cost burden on pipeline operators.

<u>Repair Criteria</u>
49 CFR § 192.933(a) specifies the overarching requirement to promptly remediate conditions that could reduce a pipeline's integrity. Section 192.933(c) specifies the timeframe for performing remediation, unless a condition meets one of the special requirements specified in §192.933(d). Each of the proposed additions to § 192.933(d) is discussed below.

Immediate Condition: Metal Loss Defects that Exceed 80% of Wall Thickness. Currently, 49 CFR §192.933(d)(1)(i) requires that a calculation of the remaining strength of the pipe that shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly be treated as an immediate condition. Suitable remaining strength calculation methods include ASME/ANSI B31G, RSTRENG, or an alternative equivalent method. These are incorporated by reference in § 192.7(c) but are only valid for metal loss defects with depths less than 80% of pipe wall thickness. The existing rule implicitly treats defects of greater than or equal to 80% defect depth as immediate conditions, as clarified in Frequently Asked Question (FAQ)-241.[27] PHMSA is proposing to explicitly list this immediate condition in §192.933(d)(1). Inclusion would not represent a new or different requirement than the existing regulation, and thus would not impose an additional cost.

Immediate Condition: Significant Stress Corrosion Cracking. Section 192.933(d)(1) requires that stress corrosion cracking be treated as an immediate condition through reference to ASME B31.8S, Section 7 (see §192.7(a)). The proposed rule defines and explicitly list significant stress corrosion cracking in §192.933(d)(1); however, by limiting the immediate condition to *significant* stress corrosion cracking (instead of *all indications* of stress corrosion cracking), this revision would represent a relaxation of the existing requirement. PHMSA proposes to treat other cracks or crack-like indications (which would include stress corrosion cracking that would not meet the definition of significant) as one-year conditions in §192.933(d)(2). Therefore, these additional specific remediation requirements would not impose an additional cost burden on pipeline operators.

Immediate Condition: Metal-Loss Affecting a Detected Longitudinal Seam, and Significant Selective Seam Corrosion. Section 192.933(d)(1) requires that metal-loss affecting a detected longitudinal seam be treated as an immediate condition through reference to ASME B31.8S, Section 7 (see §192.7(a)). PHMSA is proposing to add the following immediate conditions: an indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency, or high frequency electric resistance welding or by electric flash welding, and any indication of significant selective seam corrosion selective seam corrosion. Selective seam corrosion is a special case of metal-loss affecting a longitudinal seam, in which the corrosion occurs along the seam and becomes a groove, or crack-like defect. Pipe seams formed by direct current, low-frequency or high-frequency electric resistance welding, or by electric flash welding are particularly vulnerable to failure due to selective seam corrosion because of the higher likelihood of poor bond-line fusion characteristic of these manufacturing processes.

PHMSA is proposing to explicitly list these conditions in §192.933(d)(1); however, by limiting the immediate condition to significant selective seam corrosion (instead of all indications of selective seam corrosion), this revision represents a relaxation of the existing requirement, which requires an immediate response for all indications of selective seam

[27] FAQ-241. May I exclude metal loss indications of >80% wall loss from immediate repair requirements per 933(d)(1), if B31G or RSTRENG predict a failure pressure of greater than 1.1 times MAOP? [08/02/2006]
No. B31G and RSTRENG are not valid for situations with metal loss exceeding 80 percent of wall thickness (see Figure 1-2 in B31G, which requires "repair or replace" for conditions involving wall loss greater than 80 percent). These methods cannot be used to determine failure pressure for these situations.
The Gas Integrity Management FAQs are available online: http://primis.phmsa.dot.gov/gasimp/faqs.htm#top37

corrosion. PHMSA proposes to treat other cracks or crack-like indications (which would include selective seam corrosion that would not meet the definition of significant) as one-year conditions in §192.933(d)(2). Therefore, these additional specific remediation requirements do not impose an additional cost burden on pipeline operators.

Additional One-Year Conditions: Metal-loss and Cracks or Crack-like Defects Other than Immediate Conditions. Currently, 49 CFR §192.933(d)(2) does not explicitly list a number of conditions that are explicit in the corresponding hazardous liquid integrity management rule as scheduled conditions (refer to §195.452(h)).

The proposed rule would impose additional costs compared to existing requirements for remediation of these four proposed metal-loss one-year repair criteria, because it would require a more prompt response. The size of defects are covered under the current rule, such that repair would eventually be required in most cases.[28] However, the proposed mandatory deadline would necessitate a more timely response by operators. The cost of these proposed one-year repair criteria is evaluated in Sections 3.2.2 through 3.2.4.

<u>Preventive and Mitigative Measures</u>
49 CFR § 192.935 requires that operators identify additional preventive and mitigative (P&M) measures to protect High Consequence Areas. Operators must base the additional measures on specific risk assessments. The existing rule does not prescribe what those additional measures must be, however it does list examples of measures operators could take. The proposed rule would expand the listing of example P&M measures. Examples serve to promote awareness of the range of actions an operator could consider, but do not constitute new or different requirements.

The proposed rule would also require that seismicity be analyzed to mitigate the threat of outside force damage. Addressing seismicity is already required § 2.2(c)(3)(d) as part of addressing outside force threat, through incorporation by reference of ASME B31.8S (see § 192.917(a)). Explicit language is proposed to address Section 29 of the Act which requires operators to consider the seismicity of the geographic area in identifying and evaluating all potential threats to each pipeline segment, pursuant to 49 CFR 192 and 49 CFR 195. However, this does not constitute a new or differing requirement from the current rule.

Lastly, the proposed rule would add specific enhanced measures for managing external and internal corrosion on pipelines inside HCAs. This aspect of the proposed rule is analyzed in Topic Area 5, Corrosion Control.

Therefore, with the exception noted, the proposed changes to the P&M program element requirement would not impose an additional cost burden on pipeline operators.

<u>Periodic Evaluations and Assessments</u>
49 CFR § 192.937 requires operators to periodically assess and evaluate the integrity of covered HCA segments. PHMSA determined that conforming amendments would be needed to implement, and be consistent with, the proposed rule changes for: data integration, risk assessment, threat identification, and risk assessment (§ 192.917); baseline assessment methods (§ 192.921); decisions about remediation (§ 192.933); and

[28] In some cases, the repair timeframe might extend beyond the next assessment deadline, and might not be repaired before the subsequent assessment, in which case the anomaly would be reevaluated

identification of additional P&M measures (§ 192.935). For the reasons described in Sections 3.2.1.1 through 3.2.1.5, these conforming changes do not constitute new or differing requirements. Therefore, this requirement does not impose an additional cost burden on pipeline operators.

49 CFR § 192.941 and Appendix E, among other requirements, specify that to address the threat of external corrosion on cathodically protected pipe in a HCA segment, an operator must perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years. PHMSA proposes to make conforming edits to the language of this requirement to accommodate the revised definition of the term "electrical survey", which would be replaced with "indirect inspection" to accommodate other techniques in addition to close-interval surveys. This clarification does not change the intent of the requirement. Therefore, this clarification does not impose an additional cost burden on pipeline operators.

<u>Reassessment Interval</u>
Section 5 of the Act identifies a technical correction amending Title 49 of the U.S. Code to allow the Secretary of Transportation to extend the 7-year IM reassessment interval for an additional six months if the operator submits written notice to the Secretary with sufficient justification of the need for the extension. The proposed rule codifies this statutory requirement. Even though the notification requirement might require a negligible expenditure on the part of pipeline operators, it would be more than offset by the savings associated with having increased operational flexibility to schedule assessments beyond the mandatory seven-year deadline. Therefore, this requirement does not impose an additional cost burden on pipeline operators.

3.2.3 ANALYSIS ASSUMPTIONS

Because gas operators have not (prior to 2010) been required to report on the type of integrity repair conditions being evaluated, PHMSA assumed that the experience of hazardous liquid operators can be applied to this analysis.

3.2.4 ESTIMATION OF COSTS

This analysis is structured as follows:

1. Estimate the number of conditions to which this requirement would apply
2. Estimate the average length of time an operator has to remediate the condition under current regulation
3. Estimate the present unit cost of repair
4. Estimate the total cost of repair
5. Calculate the difference in present value of the cost of repair within one year compared to the longer average timeframe

3.2.4.1 Number of Conditions

The proposed rule will require operators to accelerate repairs on certain 180 day repair conditions. PHMSA estimated the expected number of 180 day gas transmission defects detected a year based on HCA miles and assessment and repair condition discovery data submitted in gas transmission and hazardous liquid annual reports (Table C-2).

Under current regulations HCA segments must be re-assessed every seven years. Therefore the average annual mileage is assessed is one seventh of total HCA mileage. Given potential overlap with Topic Area 1 HCA miles subject to MAOP verification tests, PHMSA did not include these miles. PHMSA therefore considered 2,407 miles of HCA lines (**Table 3-60**).

Table 3-60. Calculation of HCA Mileage, Topic Area 2

Scope	Miles
HCA[1]	19,872
HCA MAOP verification testing under Topic Area 1[2]	3,024
HCA less Topic Area 1 mileage	16,849
Average assessed per year[3]	2,407

1. Source: PHMSA Annual Reports
2. See section 3.1.
3. HCA miles less topic Area 1 divided by 7 years.

PHMSA then estimated the number of 180-day conditions which could occur on the regulated segments. Gas transmission operators do not currently report 180-day conditions separate from other scheduled repairs. As the new repair criteria are similar to those for hazardous liquid pipeline, PHMSA assumed that a similar proportion of gas transmission scheduled conditions would be classified as 180-day conditions. PHMSA estimated that approximately 81% of scheduled repair conditions will be 180-day conditions (**Table 3-61**).

Table 3-61. Hazardous Liquid Scheduled Repair Conditions, 2004-2009

Repair Condition	Number	Percent of Total
60-day conditions	4,673	19%
180-day conditions	20,468	81%
Total	25,141	100%

Source: 2004-2009 Hazardous Liquid Annual Reports; see Table C-2

Based on the information detailed above and the historical scheduled repair condition defect discovery rate on gas transmission lines (0.107 / mile, see Table C-2), PHMSA estimated that operators will discover approximately 210 180-day repair conditions per year (**Table 3-62**).

Table 3-62. Estimation of 180-Day Repair Conditions

Component	Value
HCA miles assessed per year	2,407
Scheduled repair conditions per mile assessed[1]	0.107
Expected scheduled repair conditions per year	258
180 conditions (% of scheduled conditions)	81%
Expected 180-day conditions per year	210

1. 2004-2009 Gas Transmission scheduled repair rate, see Table C-2.

3.2.4.2 Average Repair Time

Under the existing rule, remediation of these conditions could be deferred for up to 10 years or more, as described in Section 3.2.1. PHMSA does not collect data for how long an operator takes to actually complete the repair of scheduled anomalies. Because the gas IM rule requires a reassessment every seven years, conditions with a remediation schedule greater than seven years would likely be reassessed and the repair schedule adjusted based on updated assessment data. PHMSA assumed a repair schedule of 5 years as a representative average. The cost associated with the proposed requirement is then the difference between the cost of a repair performed the same year as a condition is discovered and the present value of the same repair completed in 5 years (i.e., the repair is accelerated by 4 years).

3.2.4.3 Unit Cost of Repair

The cost of repair depends in large part on the size of the pipe, the size of areas to be repaired, the type of repair, and location (geographic region). A range for the typical cost of repair activities is shown in **Table 3-63**.

Table 3-63. Range of Typical Repair Costs

Repair Method (Length)	West (Except West Coast), Central, Southwest[1]	South, West Coast	East[2]
12-inch Diameter			
Composite Wrap (5’)	$9,600	$12,000	$13,800
Sleeve (5’)	$12,800	$16,000	$18,400
Pipe Replacement (5’)	$41,600	$52,000	$59,800
Material Verification (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$16,000	$20,000	$23,000
Sleeve (20’)	$19,200	$24,000	$27,600
Pipe Replacement (20’)	$51,200	$64,000	$73,600
Material Verification[1] (20’)	$4,000	$4,000	$4,000
24-inch Diameter			
Composite Wrap (5’)	$14,400	$18,000	$20,700
Sleeve (5’)	$19,200	$24,000	$27,600
Pipe Replacement (5’)	$62,400	$78,000	$89,700
Material Verification[1] (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$24,000	$30,000	$34,500
Sleeve (20’)	$28,800	$36,000	$41,400
Pipe Replacement (20’)	$76,800	$96,000	$110,400
Material Verification[1] (20’)	$4,000	$4,000	$4,000
36-inch diameter			
Composite Wrap (5’)	$21,600	$27,000	$31,050
Sleeve (5’)	$28,800	$36,000	$41,400
Pipe Replacement (5’)	$93,600	$117,000	$134,550
Material Verification[1] (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$36,000	$45,000	$51,750
Sleeve (20’)	$43,200	$54,000	$62,100
Pipe Replacement (20’)	$115,200	$144,000	$165,600

Table 3-63. Range of Typical Repair Costs			
Repair Method (Length)	**West (Except West Coast), Central, Southwest[1]**	**South, West Coast**	**East[2]**
Material Verification[1] (20')	$4,000	$4,000	$4,000
Source: PHMSA best professional judgment 1. 80% of South/West Coast. 2. 115% of South, West Coast.			

3.2.4.4 Estimated Total Cost of Repair

Most anomalies are repaired using composite wraps or steel sleeves. Relatively few anomalies are repaired by pipe replacement. PHMSA used BPJ to estimate that

- 30% of anomalies are repaired by composite wrap
- 60% are repaired by sleeve
- 10% are repaired by pipe replacement.

Since there is variation in repair costs based on geographic locale, PHMSA distributed the estimated number of repairs to each region of the country based on the ratio of onshore gas transmission pipeline in each region:

- Eastern – 10%
- Southern and West Coast – 15%
- Southwest, Central, and West (excluding West Coast states) – 75%.

PHMSA equally distributed the numbers of repairs among the six pipe diameter/repair size combinations shown in Table 3-63. Using the above assumptions, repair costs, and estimated number of repairs, PHMSA calculated the total annual cost of performing the repairs to be approximately $14.1 million.

3.2.4.5 Cost of Accelerating Repair Timeframes

PHMSA compared the estimated annual cost of performing the one-year repairs with the present value of those same repairs if done five years in the future; in other words, four years sooner. **Table 3-64** shows the difference and represents the estimated annual cost of the proposed requirement to establish more prompt and explicit timeframes for completing metal loss repairs. **Table 3-65** shows the total and average annual present value over the study period.

Table 3-64. Present Value of Estimated Annual Cost of More Timely Repair of Non-Immediate Conditions (Millions)		
Estimate	**7% Discount Rate**	**3% Discount Rate**
Cost of repairs	$14.1	$14.1
Cost of repairs delayed 4 years	$10.8	$12.6
Difference (estimated cost of proposed rule)	$3.4	$1.6

Table 3-65. Present Value Costs, Topic Area 2 (Millions)[1]	
7% Discount Rate	**3% Discount Rate**

Total	Average Annual	Total	Average Annual
$32.7	$2.2	$19.4	$1.3
1. Total is of the 15 year compliance period; average annual is total divided by 15.			

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3.3 MANAGEMENT OF CHANGE PROCESS IMPROVEMENT

Topic Area 3 includes the following changes:

1. Evaluate and mitigate risks during Management of Change (MoC)
2. Develop MoC process beyond IMP- and Control Center-related processes

3.3.1 PROBLEM STATEMENT

Section 49 CFR § 192.13 prescribes general requirements for onshore gas transmission pipelines. The proposed rule would add a new paragraph, § 192.13(d), to establish a general clause for operators to evaluate and mitigate risks, as necessary, during all phases of the useful life of a pipeline, including managing changes to pipeline design, construction, operation, maintenance, and integrity, and to articulate specific requirements for a MoC process for onshore gas transmission pipelines.

3.3.2 ASSESSMENT OF REGULATORY IMPACT

New mandatory MoC requirements would apply to all onshore gas transmission pipelines under the proposed rule. However, similar MoC requirements currently apply to pipeline segments in HCAs and control centers, and those operators have formal processes in place to address changes that occur in those areas. Pipeline operators currently apply MoC principles to all of their pipeline systems with varying degrees of process formality. Thus, the incremental impact to operators is limited in scope.

3.3.3 ANALYSIS ASSUMPTIONS

Based on its experience and BPJ, PHMSA made the following key assumptions in estimating the costs of the proposed changes:

- Approximately 20% of the operators that do not have IM programs would have to develop processes to more formally implement the new MoC rule requirements
- A typical pipeline system has eight compressor stations and three piping sections.
- A typical pipeline system would have one compressor station change event and three piping section change events per year.

3.3.4 ESTIMATION OF COSTS

The steps for estimating costs are:

1. Estimate the number of operators that do not have IM programs.
2. Estimate the number of these operators that would have to develop MoC processes.
3. Estimate the unit costs of developing and implementing MoC processes.
4. Estimate total incremental annual compliance costs.

3.3.4.1 Estimation of Incrementally Affected Operators

Based on PHMSA gas transmission operator annual report data, there are approximately 350 onshore gas transmission system operators that do not have IM programs (do not operate HCA pipeline mileage). These operators implement MoC practices but in a less formal manner than would be required by the proposed new rule. Based on BPJ, PHMSA assumed that approximately 20% (approximately 70) of these operators would have to develop processes to more formally implement the new MoC rule requirements. Some of these operators would need to review and revise existing procedures; others would need to establish new processes.

3.3.4.2 Estimation of Unit Costs

The unit costs of the new MoC procedures for affected operators will consist of the one-time costs associated with developing or designing the new procedures and the annual/recurring costs of applying those procedures to any covered event. For both the one-time and annual costs, PHMSA used BPJ to estimate the activities, labor hours, and staff associated with creating and implementing MoC processes for: 1) cases in which nominally formal processes exist (low cost) and 2) cases where only minimal processes exist (high cost). To estimate overall unit costs, PHMSA used the average of the low and high cost estimates.

Table 3-66 shows the labor rates applied in the cost calculations. **Table 3-67** presents one-time unit costs for initial development of the new procedures; it includes a breakdown by activity and associated level of effort for both the low and high cost. **Table 3-68** provides the estimates for unit costs on a per event basis.

Table 3-66. Labor Rates

Occupation Code	Occupation	Industry	Labor Category	Mean Hourly Wage	Total Labor Cost[2]
17-2141	Mechanical Engineers	Oil and Gas Extraction	Senior engineer	$74	$99
11-3071	Transportation, Storage, and Distribution Managers	Oil and Gas Extraction	Manager	$61	$86
17-2111	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors	Oil and Gas Extraction	Project engineer	$56	$81
47-5013	Service Unit Operators, Oil, Gas, and Mining	Pipeline Transportation of Natural Gas	Operator	$30	$55

Source: Bureau of Labor Statistics Occupational Employment Statistics (May 2014) and Employer Cost of Employee Compensation (September 2015).
2. Mean hourly wage plus mean benefits ($25.01 per hour worked).

Table 3-67. Onetime Cost of Management of Change Process Development[1]

Activity	Low Estimate		High Estimate	
	Hours	Cost[2]	Hours	Cost[2]
Review existing MoC procedures for IMP- and Control Center-related changes	3	$297	0	$0

Table 3-67. Onetime Cost of Management of Change Process Development[1]				
Activity	**Low Estimate**		**High Estimate**	
	Hours	**Cost[2]**	**Hours**	**Cost[2]**
Revise and expand scope of procedures	16	$1,584	0	$0
Establish procedures	0	$0	80	$7,922
Notify personnel and provide implementation guidance and instruction	4	$396	20	$1,980
Total	**23**	**$2,277**	**100**	**$9,902**
1. Source: PHMSA best professional judgment. Low estimate reflects nominally formal existing processes and high estimate reflects only minimal existing processes.				

Table 3-68. Per Event Cost of Implementing Management of Change Processes				
Activity	**Labor Category**	**Labor Cost[1] ($/hour)**	**Hours**	**Cost**
Maintenance/operating personnel or engineer identifies a change, invoking the process	Operator	$55	1	$55
Obtain approval to pursue change	Manager	$86	1	$86
Evaluate and document technical and operational implications of the change	Sr. Engineer	$99	12	$1,188
Obtain required work authorizations (e.g., hot work and lockout-tag out permits)	Project Engineer	$81	3	$243
Formally institutionalize change in official "as-built" drawings, facilities lists, data books, and procedure manuals	Project Engineer	$81	8	$648
Communicate change to all potentially affected parties	Manager	$86	2	$172
Train and qualify involved personnel	Operator	$55	20	$1,100
Total	**NA**	**NA**	**47**	**$3,492**
1. See Table 3-66.				

3.3.4.3 Estimation of Total Incremental Compliance Costs

To estimate total onetime costs, PHMSA used the average of the low and high onetime costs ($2,277 + $9,902) / 2 = $6,090) and multiplied by the total number of operators ($6,090 × 70 = $ $426,281). To calculate annual implementation costs, PHMSA assumed that operators would experience four MoC events per year, and multiplied the per event unit cost by the number of operators and number of events ($3,492 × 70 × 4 = $977,760). PHMSA assumed that operators would develop processes in the first year following finalization of the rule, and that implementation occurs annually. **Table 3-69** shows total annual compliance costs.

Table 3-69. Present Value Costs, Topic Area 3[1]				
Component	**Total (7%)**	**Average Annual (7%)**	**Total (3%)**	**Average Annual (3%)**
Onetime process development	$426,195	$28,413	$426,195	$28,413
Annual implementation[1] ($977,760)	$9,528,729	$635,249	$12,022,608	$801,507

Table 3-69. Present Value Costs, Topic Area 3[1]

Component	Total (7%)	Average Annual (7%)	Total (3%)	Average Annual (3%)
Total	**$9,954,924**	**$663,662**	**$12,448,803**	**$829,920**

Note: Detail may not add to total due to rounding.
1. Total is present value over 15 year compliance period; average annual is total divided by 15.

3.4 CORROSION CONTROL

The proposed rule includes the following changes related to corrosion control:

1. Perform pipe coating assessment for steel onshore transmission pipe installed in ditch [49 CFR § 192.319]
2. Protective coating strength requirements [§ 192.461]. Requirements also provided as a preventive and mitigative (P&M) measure for covered segments [§ 192.935(g)]
3. Perform pipe coating assessment when there are indications of compromised integrity
4. One-year maximum for remedial action for external corrosion mitigation deficiencies [§ 192.465] and 6 months provided as a P&M measure for covered segments [§ 192.935(g)]
5. Close interval survey (CIS) required in accordance with 49 CFR Part 192 Appendix D [§ 192.465] and as a P&M measure for covered segments [§ 192.935(g)]. Appendix D also:
    a. Eliminates three criteria for acceptability in 49 CFR Part 192 Appendix D for steel, cast iron, and ductile iron structures
    b. Clarifies terminology [§ 192.3 and Appendix D]
    c. Alters acceptability criteria in Part 192 Appendix D for aluminum structures
    d. Updates interpretation of voltage measurement
6. Additional stray/interference current remedial action, including 6 months deadline for addressing [§ 192.473] and provided as a P&M measure for covered segments [§ 192.935(g)]
7. Develop and implement a gas stream monitoring program, including semi-annual reviews [§ 192.477] and provided as a P&M measure for covered segments [§ 192.935(f)]

3.4.1 PROBLEM STATEMENT

Corrosion continues to be a significant problem for gas transmission pipelines. The incident data reported by operators is shown in **Table 3-70**. Nineteen percent of reported gas transmission incidents from 2003 through 2015 were due to internal or external corrosion. Also, the annual numbers of corrosion-caused incidents occurring in that time period do not show a declining trend over time. Thus, additional requirements are needed to enhance and improve internal and external corrosion control programs required in 49 CFR Part 192, Subpart I.

Table 3-70. Reported Gas Transmission Incidents Due to Corrosion (Onshore and Offshore)

Year	Internal Corrosion	External Corrosion	Total Corrosion	Total All Causes
2003	11	11	22	93
2004	14	9	23	103
2005	7	12	19	160
2006	11	12	23	130
2007	18	17	35	110
2008	8	11	19	122
2009	10	9	19	105
2010	19	10	29	105
2011	14	4	18	114
2012	14	13	27	102
2013	13	5	18	103
2014	9	9	18	129
2015	13	8	21	129
Total	**161**	**130**	**291**	**1505**

Source: PHMSA Incident Reports

Pipe Installation

49 CFR § 192.319 currently prescribes requirements for installing pipe in a ditch, including requirements to protect pipe coating from damage during the process. However, during handling, lowering, and backfilling, pipe coating can be damaged and its ability to protect against external corrosion compromised. An example of the consequences of such damage was the 2011 rupture of TransCanada's Bison Pipeline, near Gillette, Wyoming. The probable cause of the incident was undetected coating and mechanical damage during construction, which subsequently led to pipeline failure. To help prevent recurrence of such incidents, PHMSA has determined that additional requirements are needed to verify that pipeline-coating systems for protection against external corrosion are not damaged during the installation and backfill process.

External Corrosion Coatings

49 CFR § 192.461 currently prescribes requirements for protective coating systems. However, certain types of coating systems that have been used extensively in the pipeline industry can shield the pipe from cathodic protection if the coating disbonds from the pipe. The NTSB determined this was a significant contributing factor in the major crude oil spill that occurred on an Enbridge pipeline near Marshall, Michigan in 2010. PHMSA has determined that additional requirements are needed to specify that coating should be non-shielding to cathodic protection and to verify that pipeline coating systems for protection against external corrosion have not become compromised and have not been damaged during the installation and backfill process.

<u>External Corrosion Monitoring</u>
Existing rules in 49 CFR § 192.465 require operators to monitor cathodic protection. However, the rule does not specify the timeframe in which remedial actions are required to correct deficiencies - only that remedial actions must be promptly taken. Also, the rule does not define "prompt." To address this gap, the proposed rule would amend § 192.465 to require, except for distribution lines, close-interval surveys if annual test station readings indicate cathodic protection is below the level of protection required in 49 CFR Part 192, Subpart I. The proposed rule would further define "prompt remediation" to restore adequate corrosion control as meaning within one year of identifying the deficiency.

<u>Update for Cathodic Protection</u>
Appendix D to 49 CFR Part 192 specifies requirements for cathodic protection of steel, cast iron & ductile pipelines. PHMSA has determined that this guidance needs to be updated to incorporate lessons learned since Appendix D was first promulgated in 1971. Accordingly, the proposed rule would update Appendix D by eliminating outdated guidance on cathodic protection and interpretation of voltage measurement to better align with current standards and industry practice.

<u>Interference Current Surveys</u>
Interference currents can negate the effectiveness of cathodic protection systems. 49 CFR § 192.473 prescribes general requirements to minimize the detrimental effects of interference currents. However, specific requirements to monitor and mitigate detrimental interference currents have not been prescribed in 49 CFR Part 192, Subpart I. In 2003, PHMSA issued Advisory Bulletin ADB-03-06 (68 FR 64189). The bulletin advised each operator of a natural gas transmission or hazardous liquid pipeline to determine whether new steel pipelines are susceptible to detrimental effects from stray electrical currents. Based on this evaluation, an operator should carefully monitor and take action to mitigate such detrimental effects. Since the Advisory Bulletin, PHMSA continues to identify cases where significant pipeline defects are attributed to corrosion caused by interference currents. Examples include CenterPoint Energy's CP line (2007), Keystone Pipeline (2012), and Overland Pass Pipeline (2012). Therefore, PHMSA has determined additional requirements are needed to explicitly require that operators conduct interference surveys and remediate adverse conditions in a timely manner. The proposed rule would amend § 192.473 to require that an operator's program include interference surveys to detect the presence of interference currents and to take remedial actions within 6 months of completing the survey.

<u>Internal Corrosion Monitoring</u>
49 CFR § 192.477 prescribes requirements to monitor internal corrosion by coupons or other means if corrosive gas is being transported. However, the existing rules do not prescribe that operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system changes, changing gas supply, upset conditions, or other changes. This could result in pipelines that are not monitored for internal corrosion because an initial assessment did not identify the presence of corrosive gas. In September 2000, following the explosion of a natural gas pipeline in Carlsbad, NM, PHMSA issued Advisory Bulletin ADB-00-02, dated September 1, 2000 (65 FR 53803). The Advisory Bulletin advised owners and operators of natural gas transmission pipelines to review their internal corrosion monitoring programs and consider factors that influence the formation of internal

corrosion, including gas quality and operating parameters. Pipeline operators continue to report incidents attributed to internal corrosion. Between 2003 and 2015, operators reported 161 incidents attributed to internal corrosion, suggesting the existence of gaps in existing market-based gas quality monitoring practices.

Thus, PHMSA has determined that additional requirements are needed to assure that operators effectively monitor gas stream quality to identify if and when corrosive gas is being transported and to mitigate deleterious gas stream constituents (e.g., contaminants or liquids).

3.4.2 ASSESSMENT OF REGULATORY IMPACT

This section describes the incremental impact of each of these changes.

Pipe Installation

The proposed rule adds a new paragraph 49 CFR § 192.319(c) that would require that all newly installed transmission pipe undergo a physical coating assessment using either alternating current voltage gradient (ACVG) or direct current voltage gradient (DCVG) to locate coating flaws.[29] The proposed rule further requires that moderate or severe coating damages be remediated by recoating. The rationale behind this change is that most operators perform the required high voltage holiday detection (called "jeeping") on the pipeline prior to it being set into the ditch; however, coating damage can occur after the pipe is lowered into the ditch and the ditch backfilled. Many of the high resistance coatings are brittle and any impact with a rock or the ditch wall can cause coating damage, and over time, if the cathodic protection electrical potential is not sufficient or if there are interference currents, external corrosion can occur. Besides damage to fusion bonded epoxy coatings, field wrapped joints are also prone to construction damage. Testing the newly installed pipeline after backfilling is an excellent way of finding potential flaws in the coating that occur during installation of the pipe in the ditch and that could, over time, enable external corrosion to affect pipeline integrity.

The proposed rule would require that operators perform a coating survey after initial backfill to identify coating damage that might have occurred during the backfill process. However, since this is for new pipelines only, it does not apply to existing pipelines. Therefore, there is no current cost impact on existing pipelines or pipeline operators. (Note: a similar requirement would be added to § 192.461(f) for repairs and pipe replacements performed for existing pipeline facilities.) This would be a negligible cost factor for a new pipeline project.

External Corrosion Coatings

Currently, § 192.461(a)(4) prescribes that coatings have sufficient strength to resist damage due to handling and soil stress. This paragraph would be revised in the proposed rule to clarify and expand on the types of activities covered by the general term "handling." It would specify that coatings selected have sufficient strength to adequately withstand handling throughout the entire installation process after being applied to the pipe (transportation, field handling, installation, boring, backfilling, and soil stresses). For example, this requirement would provide greater assurance that operators specify the correct

[29] Old paragraph § 192.319(c) would become paragraph § 192.319(d).

coating for the intended application (e.g., avoid pipe coatings designed for direct burial when the pipe is installed by boring methods). This requirement comports with current industry standards that have evolved in recent years to address this aspect of pipeline construction.

A new paragraph, § 192.461(f), would require a coating survey using either ACVG or DCVG whenever a repair is made that results in more than 200' of backfill or if other assessment methods show the possibility of coating issues in the area of the repair. If an operator finds either moderate or severe coating damage via the survey, then prompt remedial action would be required to mitigate the situation. Coating survey costs range from $2,000 to $50,000 per mile depending on several factors: the environment, traffic control, and the amount of miles being surveyed. The cost of repairs could add significantly more cost per mile, but over the long term these repairs would result in an improvement in pipeline integrity and a reduction in cathodic protection (CP) currents needed to protect the pipeline (and thus lengthening the life of the CP anodes).

Currently, post-backfill coating surveys are not normally being done and many locations may be left with areas that are subject to future external corrosion due to coating flaws. Often, operators find that if one area has corrosion or coating damage there are adjacent locations with similar problems. Performing testing and excavations when crews are already mobilized is significantly less expensive than having them return to an adjacent area some time later.

<u>External Corrosion Monitoring</u>

The existing rule 49 CFR § 192.465 specifies that operators take "prompt" corrective action. The proposed rule would provide more explicit standards for timeliness of corrective action by specifying that remedial action must be completed promptly, but no later than the next monitoring interval specified in § 192.465 or one year after deficiencies are discovered if no monitoring interval applies. This is consistent with PHMSA current guidance to operators. Therefore, this would have minimal regulatory impact.

In addition, the proposed rule for HCAs, § 192.935(g)(3)(i), would require remedial action within six months of the identification of a deficiency rather than one year.

A new paragraph, § 192.465(f), would require that operators perform a close interval survey (CIS) when they have a test station reading of low cathodic protection (per revised 49 CFR Part 192 Appendix D). The CIS is to be performed in both directions from the test station to the adjacent test stations. Where the CIS finds low cathodic protection exists, additional remediation must be taken, which could include doing a direct examination to determine the condition of the coating. An alternative to the direct examination may be the use of indirect inspection techniques.

PHMSA has noted that many operators have only taken readings at test stations, and when they fall below the minimum requirements of 49 CFR Part 192 Appendix D, the operators add additional voltage to rectifiers or install additional anodes without assessing the causes of the low readings. In some situations operators have increased the voltage too high, so that test stations that previously had good readings elsewhere ended up with too much CP voltage, which could be detrimental to the coatings in those locations. This type of remediation does not permanently solve the problem and may cause other issues such as coating failures. A CIS is needed to properly characterize a CP problem, determine its location, and understand the cause of the substandard reading at the test station.

In addition to the proposed new requirements for § 192.465(f), § 192.935(g)(2)(iv)(B) would require pipe-to-soil test stations be located at half-mile intervals within each HCA segment and at least one station be within each HCA, if practicable.

Cathodic Protection

49 CFR Part 192 Appendix D contains technical guidance for CP, but has not been updated since it was first promulgated in 1971. The proposed rule would update Appendix D to reflect current industry practices and technology, but would have no regulatory impact in terms of compliance. Proposed changes include for steel, iron and ductile iron structures, three of the five existing criteria (which are seldom used) would be eliminated. The remaining two criteria, which include a negative 0.85 VDC, taking voltage drop (loss of voltage due to soil resistance) into account with a saturated copper-copper sulfate half-cell, and a negative 100 millivolt polarization shift, are the main methods operators have been using to confirm adequate cathodic protection.

Some wording changes are proposed to better define how to interpret IR drop, but the technical intent is unchanged.

Some wording changes are proposed to better define what is required and for consistency with terminology used in 49 CFR Part 192 Subpart I.

Interference Current Surveys

A proposed change to 49 CFR Part 192 § 192.473(c) would require that for pipelines subject to stray currents, operators take action via a plan to minimize the detrimental effects of those currents. Further, the proposed change would add specificity to the requirements of the plan. It would require the operator to perform interference surveys, analyze the data from the surveys, and implement remedial action within six months. The sources of stray current problems are commonplace; they can result from other underground facilities, such as the CP systems from crossing or parallel pipelines, light rail systems, commuter train systems, high-voltage AC electrical lines, or other sources of electrical energy in proximity to the pipeline. If stray current or interference issues are not remediated, accelerated corrosion could occur and potentially result in a leak or rupture.

In addition the proposed new 49 CFR Part 192 § 192.935(g)(1) would require (i) periodic interference surveys whenever needed, but not to exceed every 7 years; (ii) remediation of AC interference that is greater than 50 amperes per meter squared; and (iii) documented justification if AC interference between 20 and 50 amperes per meter squared is not remediated.

Internal Corrosion Monitoring

The existing rule in 49 CFR § 192.477 requires operators to monitor internal corrosion if corrosive gas is being transported. However, the rule is silent on standards for determining if corrosive gas is being transported or if changes occur that could introduce corrosive contaminants in the gas stream. The proposed rule would require operators to develop and implement gas stream monitoring programs to measure gas stream components that could cause internal corrosion. At a minimum, quarterly testing would be required along with quarterly checks on the effectiveness of the mitigation strategy. In addition, the operator would be required to review its program every six months.

In § 192.935(f) the proposed rule would require the use of specific gas quality monitoring equipment for HCA segments, including but not limited to, a moisture analyzer, chromatograph, carbon dioxide sampling, and hydrogen sulfide sampling. The maximum amounts of contaminants that would require operator action are specified for carbon dioxide, moisture content, and hydrogen sulfide.

3.4.3 ANALYSIS ASSUMPTIONS

PHMSA estimated coating survey costs assuming an average backfill length of 500 feet. PHMSA estimated costs for close interval surveys assuming that annual test station readings for 0.5% of transmission mileage are out of specification. In addition, although not universally deployed, some operators already perform close interval surveys as a matter of good engineering practice. In these cases, operators would already be in compliance with the proposed rule. PHMSA assumed that operators are performing close interval surveys in 15% of Class 1 mileage; 10% of Class 2; 5% of Class 3; and 5% of Class 4 mileage.

In HCAs, PHMSA assumed that an additional test station would be added for each HCA mile to meet the proposed requirement to have test stations every half mile.

The proposed rule would require interference surveys be conducted in situations where the pipeline is subject to stray currents. Most pipeline segments would not be subject to this requirement. Pipeline segments subject to this requirement would be those segments in close proximity to other underground facilities, such as CP systems from crossing or parallel pipelines, light rail systems, commuter train systems, high voltage AC electrical lines, or other sources of electrical energy in proximity to the pipeline. For purposes of this analysis, PHMSA assumed that 1% of Class 1 and 2 pipelines and 3% of Class 3 and 4 pipelines would be subject to this requirement. PHMSA assumed Class 1 and 2 are mainly AC interference and Class 3 and 4 are mainly DC interference.

In addition, although not universally deployed, many operators already perform such interference surveys as a matter of good engineering practice. This is most often the case in urban/suburban areas where electrical interference is a more common occurrence. In these cases, operators would already be in compliance with the proposed rule. PHMSA assumed that operators are performing electrical interference surveys as needed in 10% of Class 1 – 10% mileage; 10% of Class 2; 70% of Class 3; and 90% of Class 4 mileage.

Gas purchase, sales, and transport contracts generally include quality standards, and pipeline operators will usually have some mechanism to monitor contract compliance. PHMSA assumed that most of the inputs to the transmission system from gathering and production areas are already monitored. Thus, PHMSA assumes 95% existing compliance for Class 1 and 80% for Class 2. For Class 3 and 4, PHMSA assumed 100% compliance because all such lines are either local distribution companies (LDCs) are operating these lines and use the monthly or quarterly data from their suppliers or have their own equipment at their gate stations. PHMSA assumed other Class 3 and 4 operators have their gas analyzed upstream by, inter alia, interstate transmission companies.

3.4.4 ESTIMATION OF COSTS

This section describes the estimation of costs for each component. The general steps for each are: estimate incremental effect in terms of number of surveys needed or mileage affected; estimate unit costs; multiply to obtain total incremental costs.

3.4.4.1 External Corrosion Coatings

The proposed rule would require coating surveys when an operator does a repair with an excavation of 200 feet or more. PHMSA used BPJ to estimate the costs for performing such surveys as shown in **Table 3-71**.

Table 3-71. Estimation of Coating Survey Costs

Class	Coating Survey Cost[1]	Number of Surveys	Cost[1]
1	$200	100	$20,000
2	$400	70	$28,000
3	$3,000	50	$150,000
4	$5,000	20	$100,000
Total	**NA**	**240**	**$298,000**

Source: PHMSA Best Professional Judgment.
1. Based on average survey length of 500 feet. Actual costs will vary depending on environment, traffic control, and survey length.

3.4.4.2 External Corrosion Monitoring

The cost of doing a close interval survey depends on the type of environment (similar to the coating survey), with the lowest cost in a Class 1 area with no traffic issues and the pipeline right of way is soil and the highest cost in a Class 4 area with the pipeline installed under pavement which must be drilled to get soil contact, and traffic restrictions are enforced and traffic plans are required (i.e. flag people, safety vehicles, etc.). PHMSA used BPJ to estimates the unit cost, mileage, current compliance, and mileage for which test station readings are out of specification (**Table 3-72**).

Table 3-72. Gas Transmission Close Interval Survey

Class	Close Interval Survey Cost ($/Mile)[1]	Mileage[2]	Current Compliance[1]	Out of Specification Test Station Readings (Annual)[1,3]	Total Costs[4]
1	$2,000	232,635	15%	0.5%	$1,977,398
2	$3,000	30,631	10%	0.5%	$413,517
3	$25,000	33,652	5%	0.5%	$3,996,120
4	$50,000	908	5%	0.5%	$215,683
Total	**NA**	**297,826**	**NA**	**NA**	**$6,602,718**

1. Source: PHMSA best professional judgment
2. Source: PHMSA 2014 Annual Report via PDM
3. Reflects long-standing requirements for operators to have CP systems and check test stations annually, and PHMSA inspection experience.
4. Calculated as the product of mileage, unit cost, out of spec rate, and (1-compliance rate).

In addition, the proposed revisions require that pipe-to-soil test stations be located at half-mile intervals within each HCA segment, and that at least one station be located within each HCA, if practicable. PHMSA used BPJ to estimate the incremental cost of this requirement as shown in **Table 3-73.**

Table 3-73. Cost to Add Test Station in HCA

HCA	Stations Required	Baseline	New Stations	Cost per Test	Total Cost

Miles[1]	per Mile	Compliance[2]	Required	Station[2]	
19,872	2	80%	7,949	$500	$3,974,492
HCA = high consequence area 1. Source: PHMSA annual reports. 2. Source: PHMSA BPJ 3. Unit cost represents approximately $400 in labor (2 workers for half day) and $100 in materials.					

3.4.4.3 Interference Current Surveys

Since interference currents can be either AC or DC, the cost to perform interference current surveys depends not only on the environment but also the type of interference. PHMSA used BPJ to estimate the cost of this requirement, as shown in **Table 3-74**. For simplicity, PHMSA assumed a seven-year survey interval consistent with the requirement in § 192.935(g)(1) applicable to HCAs.

Table 3-74. Estimation of Costs for Interference Surveys

Class	Interference Survey Cost[1] ($/mile)	Total Mileage[2]	Current Compliance[1]	Incremental Need for Surveys[1]	Compliance Mileage[3]	Total Costs[4] ($/7 years)
1	4,000	232,635	10%	1%	2,129	$8,374,864
2	5,000	30,631	10%	1%	276	$1,378,389
3	10,000	33,652	70%	3%	303	$3,028,639
4	10,000	908	90%	3%	3	$27,244
Total	**29,000**	**297,826**	**NA**	**NA**	**2,711**	**$12,809,136**

1. Source: PHMSA Best Professional Judgment
2. Source: PHMSA 2014 Annual Report via PDM
3. Calculated as total mileage × (100% - current compliance) × incremental need for surveys.
4. Calculated as compliance mileage × unit cost.

3.4.4.4 Internal Corrosion Monitoring

As a matter of routine business practice, such as monitoring gas quality for meeting tariff specifications, many operators already have monitors at gas entry points to their systems. Many interstate pipeline companies have continuous monitoring of gas quality. PHMSA used BPJ to estimate the costs of this provision, as shown in **Table 3-75**. The analysis of the data, depending on how it is recorded, would also be relatively inexpensive since an engineer would only have to review the data quarterly and look for trends or out of specification components. Thus, the added cost of monitoring for CO_2, sulfur, water, and other chemicals is either nothing or relatively inexpensive.

Table 3-75. Estimation of Costs for Internal Corrosion Monitoring					
Class	**Monitoring Equipment Cost**	**Total Number of Monitors Needed**	**% Current Compliance**	**Number of Monitors for Compliance**	**Costs**
1	$10,000	250	95%	13	$125,000
2	$10,000	50	80%	10	$100,000
3	$10,000	150	95%	8	$75,000
4	$10,000	200	95%	10	$100,000
Total	**NA**	**650**	**NA**	**40**	**$400,000**
Source: PHMSA Best Professional Judgment 1. Calculated as total number of monitors needed × (100% - % current compliance).					

3.4.4.5 Total Corrosion Control Costs

Table 3-76 summarizes the incremental compliance costs for the expansion of corrosion control. **Table 3-77** provides the present values over the 15-year study period.

Table 3-76. Summary of Incremental Costs, Corrosion Control (Millions)			
Component	**One-Time**	**Annual**	**Recurring (7 years)**
External Corrosion Coatings	$0	$0.3	$0
External Corrosion Monitoring	$4.0	$6.6	$0
Interference Current Surveys	$0	$0	$12.8
Internal Corrosion Monitoring	$0.4	$0	$0
Total	**$4.4**	**$6.9**	**$12.8**

Table 3-77. Present Value Incremental Costs, Topic Area 4[1]			
Total (7%)	**Average Annual (7%)**	**Total (3%)**	**Average Annual (3%)**
$94,788,018	$6,319,201	$118,451,243	$7,896,750
1. Calculated assuming one-time costs in year 1; annual costs in years 1-15; and 7-year recurring costs annualized over 7 years at the different discount rates. Total is present value over 15 years; average annual is total divided by 15.			

3.5 PIPELINE INSPECTION FOLLOWING EXTREME EVENTS

This topic area includes the following changes:

1. Continuing surveillance to also include other unusual operating and maintenance conditions, including changes resulting from extreme weather or natural disasters, and other similar events [§ 192.613]
2. Inspection (within 72 hours) and remedial action following extreme weather, man-made, or natural disasters, and other similar events. [§ 192.613(c)]

3.5.1 PROBLEM STATEMENT

Currently, 49 CFR § 192.613 prescribes general requirements for continuing surveillance of a pipeline to determine and take appropriate actions needed due to changes in the pipeline from, among other things, unusual operating and maintenance conditions. Weather-induced movement of the pipeline resulting in coating damage, abrasion and gouging, fatigue cracking, and subsequently failure caused a 2009 incident on an offshore pipeline. The probable cause of the 2011 hazardous liquid pipeline incident resulting in a crude oil spill into the Yellowstone River near Laurel, Montana was scouring at a river crossing due to flooding.

Based on recent examples of extreme weather events that resulted, or could have resulted, in pipeline incidents, PHMSA has determined additional requirements are needed to assure that operator procedures adequately address inspection of the pipeline and right-of-way for “other factors affecting safety and operation” following extreme weather events and natural disasters, and other similar events. Such inspections would apply to both onshore and offshore pipelines and their rights-of-way. The proposed rule would amend § 192.613(a) accordingly. In addition, the proposed rule would add a new paragraph, § 192.613(c), to require such inspections, specify the timeframe in which such inspections must be performed, and specify that appropriate remedial actions must be taken to ensure safe pipeline operations.

3.5.2 ASSESSMENT OF REGULATORY IMPACT

The proposed rule would specify that operators conduct surveillances following extreme weather or natural disaster, or similar events. Inspections would be required within 72 hours, or as soon as possible, when personnel with the equipment required for inspecting the pipeline can safely access the affected area. Additionally, the proposed revisions would require remedial actions when adverse conditions are identified.

3.5.3 ANALYSIS ASSUMPTIONS

PHMSA assumed that most operators already have right-of-way inspection, surveillance, and leakage survey procedures to monitor for conditions meeting the proposed requirements. These procedures would require minor revisions to include the proposed requirements in § 192.613. These clarifications would specify that operators must conduct surveillances following extreme weather or natural disaster, or similar events within 72 hours of the cessation of an event or as soon as possible once personnel and equipment can safely access the affected area. PHMSA notes that all operators are currently required to take remedial or mitigative measures upon discovery of an unsafe condition. As such, the analysis does not consider cost associated with remediation of damage due to the event. The cost and benefit of this proposed requirement is that it sets a standard for timely inspection and surveillance of pipelines in the wake of an extreme event, in order to discover damage caused by the event before the pipeline fails in service.

Most gas transmission operators would need to update their existing surveillance and patrol procedures. PHMSA assumed that approximately 50 percent of operators would need only minor revisions to their procedures and programs and 50 percent may require a more substantial effort to update programs to address extreme events.

3.5.4 ESTIMATION OF COSTS

PHMSA used BPJ to estimate the costs of this provision as shown in **Table 3-78**.

Table 3-78. Estimation of Costs for Process Development for Extreme Events

Activity	Hours (Low)	Hours (High)	Cost per Operator (Low)[1]	Cost per Operator (High)[1]	Total Cost (Low)[2]	Total Cost (High)[2]	Total Cost (Average)
Review existing	2	1	$198	$99	$100,683	$50,342	$75,512

Table 3-78. Estimation of Costs for Process Development for Extreme Events							
Activity	**Hours (Low)**	**Hours (High)**	**Cost per Operator (Low)[1]**	**Cost per Operator (High)[1]**	**Total Cost (Low)[2]**	**Total Cost (High)[2]**	**Total Cost (Average)**
surveillance and patrol procedures to validate adequacy for extreme events							
Revise surveillance and patrol procedures	5	20	$495	$1,980	$251,708	$1,006,830	$629,269
Notify involved personnel of new procedures, providing implementation guidance and instruction	5	10	$495	$990	$251,708	$503,415	$377,561
Total	**12**	**31**	**$1,188**	**$3,069**	**$604,098**	**$1,560,587**	**$1,082,342**
Source: PHMSA best professional judgment 1. Calculated as hours × labor cost for senior engineer ($99; see Table 3-66). 2. Calculated as cost per operator × 50% × 1,017 operators.							

PHMSA used the average cost value above to estimate the present value of compliance costs as shown in **Table 3-79**.

Table 3-79. Present Value Costs, Topic Area 5[1]			
Total (7%)	**Average Annual (7%)**	**Total (3%)**	**Average Annual (3%)**
$1,082,342	$72,156	$1,082,342	$72,156
1. Total is present value over 15 year study period; average annual is total divided by 15 years.			

3.6 MAOP EXCEEDANCE REPORTS AND RECORDS VERIFICATION

This topic area includes the following proposed changes to 49 CFR Part 192:

1. New mandatory reporting of MAOP exceedances [§ 191.1, § 191.23]
2. New requirement for operations and maintenance (O&M) procedures to assure MAOP is not exceeded by amount needed for overpressure protection [§ 192.605(b)(13)]
3. New requirements for verification of MAOP-related records and clarification of records preparation and retention requirements [§ 192.619(f), §192.13(e), Appendix A].

3.6.1 PROBLEM STATEMENT

This section discusses the need for each of the changes.

Reporting of MAOP Exceedances

Section 23 of the Act requires that operators report each exceedance of the MAOP beyond the build-up allowed for operation of pressure-limiting or control devices. The proposed rule would codify this statutory requirement.

On December 21, 2012, PHMSA published Advisory Bulletin ADB-2012-11, to advise operators of their responsibility under Section 23 of the Act to report such exceedances. The advisory bulletin further stated:

> This reporting requirement is applicable to all gas transmission pipeline facility owners and operators. In order to comply with this self-executing provision, PHMSA advises owners and operators to submit this information in the same manner as SRC reports. The information submitted by owners and operators should comport with the information listed in § 191.25(b), and the reporting methods listed in § 191.25(a) should be employed.
>
> The reporting exemptions for SRC reports listed in § 191.23(b) do not apply to the reporting requirement for exceedance of MAOP plus build-up. Specifically, § 191.23(b)(4), which allows for non-reporting if the SRC is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the SRC report, does not apply. Gas transmission owners and operators must report the exceedance of MAOP plus build-up regardless of whether the exceedance is corrected before five days have passed.
>
> Finally, owners and operators have five days after occurrence to report exceedance of MAOP plus build-up.

Even though this provision of the Act is self-executing, PHMSA proposes to revise 49 CFR 191.23 to codify this requirement and provide consistent procedure, format, and structure for submittal of such reports by all operators.

The reporting requirements for exceedance of MAOP plus build-up currently exist in Part 191 and the only change involves deletion of the reporting exemption for exceedance of MAOP for transmission lines in cases where the condition is corrected within five days, in order to conform to the statutory mandate. Operators were required to begin reporting MAOP exceedances, and have been doing so, since 2012. Forty such reports have been received by PHMSA as of the date of this report.

Prior to the statute, operators were already required to report such exceedances as specified in 49 CFR 191.23. However, actual filing of the report was not required if the condition was corrected before expiration of the reporting deadline. In effect, this requires that all such exceedances be reported, instead of only those that are not corrected within the 10-day reporting deadline. Because of this existing requirement, operators already have procedures and processes in place to identify, document, and report such exceedances. This rule would merely require the actual filing of the reports, which previously might not have to be filed.

<u>O&M Procedures</u>

Implicit in the proposed requirements of 49 CFR 192.605 is the intent for operators to establish operational and maintenance controls and procedures to effectively preclude operation at pressures that exceed MAOP. PHMSA expects that operators' procedures should already address this aspect of operations and maintenance, as it is a long-standing, critical aspect of safe pipeline operations. However, § 192.605 does not explicitly prescribe this aspect of the procedural controls, which is added to § 192.605(b)(13). Since this change is a clarification of existing requirements, this requirement does not impose an additional cost burden on pipeline operators.

MAOP Records Verification

49 CFR § 192.603(b) prescribes the general requirement to maintain records for operating, maintaining, and repairing the pipeline in accordance with each of the O&M requirements of 49 CFR Part 192, Subparts L (operations) and M (maintenance). Subpart L (specifically § 192.619) prescribes requirements for establishing the MAOP of the pipeline. Section 23 of the Act requires that operators verify the existence and sufficiency of records used to confirm MAOP. The purpose of the verification is to ensure that the records accurately reflect the physical and operational characteristics of the pipelines and to confirm the established MAOP of the pipelines. The Act requires the verification to be completed within six months following enactment of the Act. PHMSA issued Advisory Bulletin 11-01 on January 10, 2011 (76 FR 1504) and Advisory Bulletin 12-06 on May 7, 2012 (77 FR 26822) to inform operators of this required action. Advisory Bulletin 12-06 further stated:

> As directed in the Act, PHMSA would require each owner or operator of a gas transmission pipeline and associated facilities to verify that their records confirm MAOP of their pipelines within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in HCAs.
>
> PHMSA intends to require gas pipeline operators to submit data regarding mileage of pipelines with verifiable records and mileage of pipelines without records in the annual reporting cycle for 2013. On April 13, 2012, (77 FR 22387) PHMSA published a Federal Register Notice titled: ''*Information Collection Activities, Revision to Gas Transmission and Gathering Pipeline Systems Annual Report, Gas Transmission and Gathering Pipeline Systems Incident Report, and Hazardous Liquid Pipelines Systems Incident Report.*'' PHMSA plans to use information from the 2013 Gas Transmission and Gathering Pipeline Systems Annual Report to develop potential rulemaking for cases in which the records of the owner or operator are insufficient to confirm the established MAOP of a pipeline segment within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in HCAs. Owners and operators should consider the guidance in this advisory for all pipeline segments and take action as appropriate to assure that all MAOP and MOP are supported by records that are traceable, verifiable and complete.

As discussed above, the requirement for verification of records used to establish MAOP is mandated in Section 23 of the Act and articulated by PHMSA in Advisory Bulletin 11-01 and reiterated in Advisory Bulletin 12-06. In addition, documentation of verification records used to establish MAOP is required in the annual reporting cycle for 2013.

PHMSA has determined additional rules are needed to implement this requirement of the Act and ensure that future records used to establish MAOP are reliable, traceable, verifiable, and complete. The proposed rule would add new paragraphs §§ 192.13(e) and 192.619(f), to codify this requirement, to elaborate on the general recordkeeping requirement in § 192.603 with respect to records used to establish MAOP, and to require that such records be retained for the life of the pipeline. The statutory mandate to complete and report on verification of records used to establish MAOP in 2013 must be completed before the proposed rule would be promulgated (in fact, such reporting was completed as of June 30, 2013).

PHMSA has determined that an important aspect of compliance with MAOP records verification requirements is to assure that records that demonstrate compliance with Part 192 are complete and accurate. The proposed rule would add new paragraph § 192.13(e) to more clearly articulate the requirements for records preparation and retention and to require that records be reliable, traceable, verifiable, and complete. The proposed new 49 CFR Part 192 Appendix A would provide specific requirements for records retention. These changes are clarifications of requirements only. Proposed § 192.619(f) would require operators to maintain records that establish the pipeline MAOP, which include but are not limited to design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type, and other related data.

3.6.2 ASSESSMENT OF REGULATORY IMPACT

As discussed in Section 3.6.1 above, operators are in compliance with the proposed requirements in this topic area. PHMSA assessed the regulatory impact from the prestatutory baseline. That is, PHMSA estimated the cost of meeting these requirements.

3.6.3 ANALYSIS ASSUMPTIONS

PHMSA based estimation of the incremental cost of this provision on the burden estimates in the applicable Information Collection Requests (ICRs).

3.6.4 ESTIMATION OF COSTS

PHMSA used Safety Related Condition (SRC) and annual report data, the estimates of burden in the ICRs for the SRC and Gas Transmission Annual Report, and the labor rates in Table 3-66, deflated to year dollars incurred, to estimate costs of compliance.

Reporting of MAOP Exceedances

Section 23 of the Act requires that operators report each exceedance of the MAOP beyond the build-up allowed for operation of pressure-limiting or control devices. **Table 3-80** summarizes the number of MAOP exceedance SRC reports on gas transmission pipelines.

Table 3-80. MAOP Exceedence Reports from Gas Facilities

Year	MAOP Exceedance Reports
2012	5
2013	21
2014	21
2015	17

Source: PHMSA Safety Related Condition Reports: MAOP exceedance reports on gas transmission pipelines

On average operators submitted 16 MAOP exceedance reports per year. The most recent supporting statement for the SRC ICR indicates each SRC takes approximately six hours to complete.[30] Based on the fully loaded labor rate of $99 per hour for a senior mechanical engineer (see Table 3-66), the average annual cost for MAOP reporting is $9,500.

MAOP Records Verification

Operators incurred a cost to complete a MAOP records review and report that information to PHMSA on annual reports. PHMSA assumed that operators incur a burden to complete

[30] http://www.reginfo.gov/public/do/PRAViewICR?ref_nbr=201405-2137-001

initial records checks and then negligible costs thereafter. In the supporting statement for the Gas Transmission Annual Report ICR, PHMSA estimated that it would take operators approximately 20 hours to complete records checks for 1,440 reports. [31] PHMSA estimated one-time costs of $2.9 million based on a fully loaded labor rate of $99/hr. (Table 3-66).

Summary of Costs for MAOP Exceedance Reporting and Records Verification
PHMSA assumed that operators have already completed records verification and MAOP exceedance reporting from 2012 to 2015. For this analysis, PHMSA deflated costs that occurred in the past using the CPI.

Table 3-81. Previously Incurred Compliance Costs (2015$)

Year	MAOP Exceedance Reporting[1]	Records Verification	Total at Current Labor Rates	Estimated Cost Incurred[3]
2012	$2,970	$2,851,200[2]	$2,854,170	$2,764,781
2013	$12,474	$0	$12,474	$12,260
2014	$12,474	$0	$12,474	$12,459
2015	$10,098	$0	$10,098	$10,098
Total	$38,016	$2,851,200	$2,889,216	$2,799,598

NA = not applicable
1. Reports from Table 3-80 times six hours times $99/hour labor rate from Table 3-66.
2. 1,440 reports times 20 hours times $99/hour labor rate from Table 3-66.
3. Cost at labor rates in year occurred approximated using the Bureau of Labor Statistics Consumer Price Index – All Urban Consumers (average annual value for 2015: 237.0; 2014: 236.7; 2013: 233.0; 2012: 229.6).

Table 3-82 summarizes the discounted compliance costs for MAOP exceedance reporting and records verification assuming a pre-statutory baseline.

Table 3-82. Present Value Costs, Topic Area 6 (2015$)[1]

Total (7%)	Average Annual (7%)	Total (3%)	Average Annual (3%)
$2,892,219	$192,815	$2,916,460	$194,431

1. Total is present value over 15 year study period; average annual is total divided by 15 years.

3.7 LAUNCHER/RECEIVER PRESSURE RELIEF

This topic area includes the addition of the following safety features on launchers and receivers [§ 192.750]:

1. Require pressure relief device, and
2. Require pressure reading device, or prevention of opening while pressurized.

3.7.1 PROBLEM STATEMENT

Fatalities and injuries have occurred due to operation of pig launchers and receivers. For example, on June 25, 2012, one worker was killed and two more were injured at a BP America Production Company Facility caused by incorrect operation leading to overpressure and failure of a pig launcher.[32] The facility was not equipped with a pressure

[31] http://www.reginfo.gov/public/do/PRAViewICR?ref_nbr=201209-2137-001, operators may have to submit multiple reports
[32] https://www.rmecosha.com/ndakotastanddown/BP_Industry_Safety_Alert.pdf

relief valve.

PHMSA has determined that more explicit requirements are needed for safety when performing maintenance activities that utilize launchers and receivers for inserting and removing maintenance tools and devices. Such facilities are subjected to pipeline system pressures. Current regulations for hazardous liquid pipelines (49 CFR Part 195) have, since 1981, contained such safety requirements for scraper and sphere facilities (§ 195.426). However, current regulations for gas pipelines (49 CFR Part 192) do not similarly require controls or instrumentation to protect against inadvertent breach of system integrity due to incorrect operation of launchers and receivers for inline inspection tools, scraper, and sphere facilities. Accordingly, the proposed rule would add a new section, § 192.750, to require a suitable means to relieve pressure in the barrel and either a means to indicate the pressure in the barrel or a means to prevent opening if pressure has not been relieved.

3.7.2 ASSESSMENT OF REGULATORY IMPACT

The regulatory impact of rulemaking requiring the addition and use of new safety features when performing maintenance activities using launchers and receivers is minor due to the current widespread use of such safety measures. The use of safety measures such as pressure relief valves, pressure reading devices, and procedures that do not allow the opening of launchers and receivers while pressurized is already standard industry practice. Thus, the likelihood that these safety devices have been installed and precautionary procedures put in place has increased. Additionally, it is likely that information and lessons learned regarding past incidents and near misses involving launchers and receivers have been shared among operators and in industry forums due to the potential danger to workers.

3.7.3 ANALYSIS ASSUMPTIONS

Section 3.7.4 provides a detailed analysis of the estimated cost of these proposed changes is presented in. The key assumptions used in the analysis are:

- Almost all installed launchers and receivers already utilize safety devices.
- Less than 10 legacy launchers or receivers would require installation of new safety devices.
- 50% of the installations are to be on lines 16 inches in diameter or less; the remainder on line sizes greater than 16 inches in diameter.
- The ten launchers or receivers requiring modification would involve ten separate pipeline operators.
- Regardless of the proposed rulemaking, the design and construction of future launchers and receivers would incorporate these safety features, as part of standard industry practices currently in use.

The proposed rule would specify that the new safety devices be installed within six months of the effective date of the new section § 192.750.

3.7.4 ESTIMATION OF COSTS

PHMSA used BPJ to estimate the cost of creating specifications (design, installation, and testing) for pressure relief systems for launcher/receiver facilities, as shown in **Table 3-83.**

Table 3-83. Estimation of Costs for Creating Launcher and Receiver Pressure Specifications

Activity	Hours	Cost[1]	Number of Systems	Total Cost
Review existing design, installation, and testing specifications for launcher/receiver facilities.	1	$99	10	$990
Revise specifications to comply with new §192.750.	24	$2,376	10	$23,760
Total	**25**	**$2,475**	**10**	**$24,750**

Source: PHMSA best professional judgment
1. Calculated as hours × labor cost for senior engineer ($99; see Table 3-66).

PHMSA used BPJ to estimate the cost of designing, installing, and testing a pressure relief system for launcher/receiver facilities, as shown in **Table 3-84**.

Table 3-84. Estimation of Costs for Launcher and Receiver Safety Device Installation

Component	Cost per Small Line[1] (<16”)	Cost per Large Line[2] (>16”)	Incremental Number of Devices, Small Lines	Incremental Number of Devices, Large Lines	Total Cost
Closure	$7,000	$25,000	5	5	$160,000
Trap	$10,000	$25,000	5	5	$175,000
Total	**$17,000**	**$50,000**	**10**	**10**	**$335,000**

Source: PHMSA best professional judgment
1. Pressure relieving closure for 8" line size with 12" trap including installation and testing.
2. Pressure relieving closure for 30" line size with 36" trap including installation and testing.

The total one time cost of this action is the sum of the two total values above, which equals $359,750.

3.8 EXPANSION OF GAS GATHERING REGULATION

Topic Area 8 includes the following proposed regulatory changes:

1. Revise the current definition of a gas gathering line; establish new, first-time definitions for onshore production facility or onshore production operation, gas processing plant, and gas treatment facility; and repeal the use of American Petroleum Institute (API) Recommended Practice (RP) 80 as the regulatory basis for identifying regulated onshore gas gathering lines. [§ 192.3]
2. Expand the scope of regulated onshore gas gathering lines to include lines in Class 1 locations that operate at greater than or equal to 20% of SMYS and which are greater than or equal to 8” in diameter. These lines would become subject to a subset of regulatory requirements (corrosion protection, damage prevention, and certain other safety provisions). [§ 192.8, § 192.9]
3. Repeal the current exemption to file reports for certain gas gathering lines in accordance with 49 CFR Part 191. The proposed rule would require that operators of

all gas gathering lines be subject to the following:

a. immediate notice of incidents [§ 191.5];
b. reporting of incidents [§ 191.15];
c. reporting of safety related conditions (SRCs) [§ 191.23];
d. reporting of annual pipeline summary data [§ 191.17]; and
e. reporting to PHMSA's National Registry of Pipeline Operators [§ 191.22].

Section 3.8.1, 3.8.2, and 3.8.3 address each of these three regulatory changes separately.

3.8.1 REVISE THE DEFINITION OF GAS GATHERING LINE

This section addresses the gas gathering line definition.

3.8.1.1 Problem Statement

Inspection and enforcement of the current regulatory requirements for regulated gas gathering lines is hampered by the conflicting and ambiguous language of API RP 80, a complex recommended practice that can produce multiple interpretations for the same gathering pipeline system. This practice has led to the classification of gas gathering lines in ways that were not intended when API RP 80 was adopted by PHMSA in 2006.[33] This ambiguity could result in some gas gathering lines being operated out of compliance with PHMSA's pipeline safety regulations resulting in increased risk to the public, workers, and the environment.

The proposed rule would repeal use of API RP 80 as the basis for identifying regulated onshore gas gathering lines and would establish new definitions for 'onshore production facility or onshore production operation,' 'gas processing plant,' and 'gas treatment facility,' and a revise the definition for 'gathering line,' to determine the beginning and endpoints of each onshore gas gathering line. The proposed rule would not reference API RP 80 definitions for gathering lines or gathering line categories.

3.8.1.2 Assessment of Regulatory Impact

The proposed revised definition for "gathering line" is a clarification of the existing requirement, although the classification of some gathering lines may change as a result. The definition is consistent with the original intent of the 2006 rulemaking. Pipelines commonly referred to as "farm taps," serving residential, commercial, or industrial customers, would not meet the revised gathering line definition and would continue to be classified as either transmission or distribution lines.

Compliance costs for gas gathering pipeline operators would be negligible because a relatively small amount of mileage for each operator in comparison to their total regulated mileage would be involved; some of these costs would be offset by lowered compliance costs when some lines are newly excluded from PHMSA regulation; and incremental costs for any new requirements would also be partially offset by activities already undertaken in accordance with existing industry practice.

[33] *Ibid*. 10

3.8.2 EXPAND THE SCOPE OF REGULATED ONSHORE GATHERING LINES

This section addresses the expansion of the scope of regulated gas gathering lines.

3.8.2.1 Problem Statement

Since 2007 the oil production in the United States has surged 71%, while natural gas production has grown nearly 30%,[34] due to breakthroughs in extraction technologies. Development of shale oil deposits and tight gas production is altering not just the extent, but also the characteristics of the nation's gas transmission and gathering systems. New gas fields are being developed in new geographic areas, requiring entirely new gas gathering systems and networks of new gas gathering lines.

Producers are employing gathering lines with larger diameters and/or higher operating pressures to support the new high volume production wells, with higher throughputs of gas. Gathering lines are being constructed as large as 36 inches in diameter with maximum operating pressures up to 1480 psig. These characteristics far exceed past design and operating parameters of typical gathering lines.

Most of these new gas gathering lines are unregulated and PHMSA does not collect incident data or annual report data on these unregulated lines. However, PHMSA is aware of incidents indicative that these lines are subject to the same sorts of failure modes common to other pipelines that PHMSA does regulate. For example, on November 14, 2008, three homes were destroyed and one person injured when a gas gathering line exploded in Grady County, Oklahoma. On June 8, 2010, two workers died when a bulldozer struck a gas gathering line in Darrouzett, Texas. On June 29, 2010, three men working on a gas gathering line in Grady County, Oklahoma were injured when it exploded.

The dramatic expansion in natural gas production and changes in typical gathering line characteristics requires PHMSA to review its regulatory approach to gas gathering pipelines to address safety and environmental risk.

A 2014 GAO report recommends[35] PHMSA address the increased risk posed by new larger-diameter, higher-pressure gas gathering pipelines. The National Association of Pipeline Safety Representatives (NAPSR) Resolution No. 2010-2 AC-2[36] also supports regulating additional, currently unregulated onshore gas gathering lines. Consistent with the NAPSR Resolution, PHMSA is proposing to regulate the operation of gas gathering pipelines that:

(1) Are located in a Class 1 location, and
(2) Operate at MAOP ≥ 20% SMYS, and
(3) Are ≥ 8 inches in diameter.

The proposed new category of regulated lines would be designated Type A, Area 2. Type A, Area 2 gas gathering line segments would be subject to the following subset of 49 CFR Part

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[34] Energy Information Administration, "Crude Oil Production," and "Natural Gas Production: Gross Withdrawals," retrieved April 9, 2014. www.eia.gov.
[35]GAO Report GAO-14-667, "*Oil and Gas Transportation, Department of Transportation is Taking Actions to Address Rail Safety, but Additional Actions Are Needed to Improve Pipeline Safety*,' August 2014. p. 48.
[36] Letter from Danny McGriff, National NAPSR Chair, Georgia Public Service Commission, to Jeffrey D. Wiese, Associate Administrator, Pipeline and Hazardous Materials Safety Administration, dated November 1, 2010, *Resolutions Passed during 2010 NAPSR National Meeting*

192 regulatory requirements:

(1) For new, replaced, relocated, or otherwise changed lines, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of Part 192;
(2) For metallic pipelines, corrosion must be controlled in accordance with the requirements of Part 192, Subpart I ;
(3) A damage prevention program must be conducted under § 192.614;
(4) An emergency plan must be established and implemented under § 192.615;
(5) A public awareness program must be conducted under § 192.616;
(6) The MAOP of the lines must be established under § 192.619; and
(7) Line markers must be installed and maintained in accordance § 192.707.

The proposed regulation focuses on preventive measures for the most frequent causes of failure (corrosion and excavation damage) and on emergency preparedness. Minimum federal safety standards would bring an appropriate level of consistency to the current mix of regulations that differ from state to state.

3.8.2.2 Assessment of Regulatory Impact

The regulatory impact of the proposed rule is the mandatory application of a subset of requirements in 49 CFR Part 192 that apply to gas transmission lines to a substantial amount of currently unregulated gas gathering pipelines. The impact is limited to higher-risk lines (i.e., larger lines that operate at higher pressures) and the most likely causes and impacts of pipeline failure.

3.8.2.3 Analysis Assumptions

Compliance costs for the proposed regulation depend on the extent to which operators already comply. Many operators are already subject to the proposed regulations since they operate other regulated pipeline segments and already have safety programs in place for compliance. Some of these operators may already apply their relevant safety programs to their unregulated gathering pipelines as a matter of good business practice. Additionally, many states already require some of the provisions included in the proposed rule (e.g., state damage prevention laws) so operators won't incur substantial additional compliance costs. These factors are described more fully in Section 3.8.2.4. For this analysis, PHMSA assumed that many operators already substantially comply with some portions of the proposed rule.

3.8.2.4 Estimation of Costs

PHMSA analyzed two groups of operators: those not currently operating regulated gas pipelines (group 1) and those currently operating regulated gas pipelines (group 2). Costs to operators in group 2 are likely less because these operators already perform all of the requirements and costs would be limited to the inclusion of additional mileage under existing regulatory compliance programs.

The steps to estimate costs are:

1. Estimate the unit cost ($/mile) for implementing each specific requirement.
2. Estimate mileage of gas gathering pipelines that would be newly regulated.
3. Multiply unit costs by mileage to obtain total incremental compliance costs.

3.8.2.4.1 Estimation of Unit Costs

The Independent Petroleum Association of America (IPAA)[37] provided cost information for a 2006 rulemaking. The 2006 rule included five provisions common to this proposed rulemaking:

1. Initial population survey and periodically recurring population surveys.
2. Initial capital costs and annually recurring costs for corrosion control programs.
3. Initial capital costs and annually recurring costs for line markers and line marker maintenance.
4. Annually recurring costs for damage prevention programs.
5. Annually recurring costs for public education programs.

The unit cost assumptions in the 2006 RIA are shown in **Table 3-85**, updated to current year dollars. The sections below describe the BPJ adjustments PHMSA made to these unit costs for analysis of each provision of the proposed rulemaking.

Table 3-85. Unit Cost of 2006 Expanded Safety Provisions ($ per mile)

Component	Initial Capital Cost (2006$)[1]	Operating (Recurring) Costs (2006$)[1]	Initial Capital Cost (2015$)[2]	Operating (Recurring) Costs (2015)[2]
Population survey	$588	$118	$642	$129
Corrosion control	$17,183	$449	$18,751	$490
Line markers	NA	$153	NA	$166
Damage prevention	NA	$259	NA	$282
Public education	NA	$198	NA	$216

1. Source: IPAA, as cited in PHMSA, 2006, Final Regulatory Evaluation, Regulated Natural Gas Gathering Lines.
2. Updated from 2006 dollars using the BLS All-City Consumer Price Index, averaged through November (2006 CPI: 201.6; 2015 CPI: 237.0)

<u>Population Surveys</u>

For the proposed rule there should be little, if any, costs associated with initial surveys. The 2006 Gas Gathering Rule required surveys for all gathering pipelines to determine if each pipeline is regulated or unregulated. The results of those surveys can largely be used for the proposed rule.

Additional periodic survey (continuing surveillance) costs may be incurred. For operator that do not run existing continuing surveillance programs (group 1), PHMSA used 100% of the IPAA estimate.

For operators that do run existing continuing surveillance programs (group 2), PHMSA expects that the additional costs of adding mileage to ongoing surveillance programs would be less. Routine observation during the normal course of operations and maintenance is expected to detect many (if not all) of the potential changes in class location that are the focus of this proposed requirement. Changes in class location involve, for example, the

[37] U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Final Regulatory Evaluation, Regulated Natural Gas Gathering Lines, Docket RSPA-1998-4868.

readily-detectable construction of new buildings near pipeline rights-of-way. PHMSA estimated the unit cost to operators in group 2 to add gathering line mileage to their existing continuing surveillance programs to be 25% of the IPAA estimate.

Corrosion Control

PHMSA estimated that initial capital start-up costs to implement corrosion control for group 1 operators are 100% of the IPAA estimates of one-time and recurring costs.

If an operator already has a corrosion control program for other, regulated lines (group 2), then costs are expected to be less due to expertise and resources already dedicated to this aspect of an operator's business. However, substantial initial capital costs for procurement and installation of corrosion control equipment would still be required for currently unprotected lines. In those cases, PHMSA estimated start-up and recurring costs are 75% of the IPAA estimate for lines not currently under cathodic protection.

Where cathodic protection already exists on currently unregulated gathering lines (both group 1 and 2), PHMSA assumed substantially compliant corrosion control programs also exist. For those cases, essentially all of the capital equipment and most, but possibly not all, of the recurring corrosion control elements that would be required are assumed to be already in place. Thus, there should be no significant start-up capital costs, and recurring costs are estimated to be approximately 5% of the IPAA estimate.

Line Markers

Operators of currently regulated gathering lines (group 2) must already place and maintain line markers for buried lines in accordance with requirements under §192.707. They should, for all practical purposes, have developed programs to ensure that those requirements are met, to manage line marker maintenance (likely done in part during right-of-way surveillance), and to ensure line markers are installed as required for new lines. This would include related elements such as marker specifications.

Operators not currently operating regulated gathering lines (group 1) may or may not have similar programs in place. For these operators, PHMSA used the recurring maintenance cost estimate of 100% of the original IPAA estimate. This would include the initial cost to an operator of developing and documenting a line marker program, as well as initially specifying, procuring, and installing the markers.

For operators already having regulated assets (group 2) PHMSA assumes that costs are 50% of the IPAA estimate. As noted, these operators will not incur additional costs to develop their line marker programs and should already have the majority of their line markers in place. The only additional costs should come from adding newly-regulated lines to their programs, and procuring and installing additional markers.

Damage Prevention Programs

The original estimate provided by IPAA included the initial costs to an operator for developing and documenting a new program, and implementing the program. However, operators of currently regulated gathering lines (group 1) must already have and carry out written excavation damage prevention programs in accordance with requirements under § 192.614. Section 192.614(b) requires a regulated operator to comply with the requirements of § 192.614(c) through participation in a qualified one-call system where there is one in place. Operators that have any regulated gathering lines (i.e., group 1) should already have and implement those programs to ensure that the requirements are met.

In addition, all States have excavation damage prevention laws in place. The requirements for pipeline operators under State one-call laws address to a large extent the requirements of § 192.614. These laws, with few exceptions, require underground facility operators to participate in the one-call system(s) within the state. Through the one-call system an operator will be notified when an excavator plans to excavate near the operator's lines. The operator must then locate and mark the lines to prevent them from being damaged during excavation. PHMSA is not aware of any states that exempt gathering lines from state damage prevention laws (i.e., both group 1 and group 2 operators must comply with State damage prevention laws).

Thus, all gathering line operators (whether or not they operate gathering lines regulated under Part 192) already have to adhere to State laws to meet those requirements and costs to operators of the proposed rule in this regard is believed to be minimal. Therefore, for this analysis, PHMSA assumed a weighted average recurring cost to all gathering line operators across all states of 5% of the IPAA estimate to account for the cost of developing and maintaining a written damage prevention program (a written program description is not typically required by State laws) for operators in group 1, or to add additional lines to its existing program documentation for operators in group 2.

Public Education (Awareness) Programs

PHMSA assumed 100% of the IPAA estimate for the recurring costs of the proposed requirement would apply for each newly-regulated gathering pipeline operator (group 1). However, 49 CFR § 192.616 requires that all currently regulated gas gathering pipeline operators must develop and implement a written continuing public education program that follows the guidance provided in API RP 1162. Operators of currently regulated gathering lines (group 2) have developed and continue to implement those programs. For these operators, PHMSA assumed incremental costs for the proposed requirement to be 10% of the IPAA estimate.

Establishing MAOP

Consistent with the regulatory analysis for the 2006 rulemaking,[38] establishing MAOP does not require significant physical work along the pipeline. Instead, this involves a review of pipeline records to identify the pressures to which the pipeline was tested and/or at which it has operated.[39] These costs are incurred for major portions of each pipeline system rather than on a per-mile basis. For many pipelines, no new costs would be required, since an MAOP would already have been determined or easily established using previous operating pressures. For other pipelines, these costs would be primarily administrative in nature, and very small as a result. Therefore, PHMSA assumed the total costs for this requirement would be negligible.

Design, Installation, and Testing of New, Replaced, Relocated, or Changed Lines

[38] *Ibid*. 33

[39] The newly regulated onshore gathering lines would be allowed to establish MAOP in accordance with 192.619(c), commonly referred to as the "grandfather clause," which allows the operator to use the highest actual operating pressure experienced in the five years prior to the effective date of the proposed rule as the MAOP.

The compliance costs for new, replaced, or changed pipelines are insignificant because operators would be able to account for compliance with PHMSA requirements as part of the decision-making and planning process. Typical industry construction practices follow industry standards and are already very similar to PHMSA's design and construction regulations. The primary differences in the design, testing, and record keeping phases are minor compared to the more expensive right-of-way, material acquisition, and installation phases that constitute the vast majority of the total construction costs. Therefore, incremental compliance costs associated with this new requirement are negligible relative to the other estimated costs.

Compliance for Emergency Preparedness

The proposed rule would require gas gathering operators to develop a written emergency plan in compliance with § 192.615. PHMSA conservatively estimated the cost to develop and implement emergency plans for each newly-regulated gathering line operator (group 1) is $325/mile/year.

Any operator with a currently regulated Type A gas gathering line or any gas transmission line segments (group 2) is already required to have such a program for those segments. In such cases, the operator would need to review and expand (if needed) existing plans to address additional pipeline segments. The cost for group 2 operators that only need to review/expand existing plans is estimated to be approximately $20/mile/year.

Summary of Unit Costs of Compliance

Table 3-86 summarizes the estimated unit costs of compliance as discussed above.

Table 3-86. Summary of Estimated Unit Costs, Unregulated Onshore Gas Gathering Pipelines			
	Operators of Currently Unregulated Lines (Group 1)	**Operators of Currently Regulated Lines (Group 2)**	**Operators of Lines with Cathodic Protection Subject to Damage Prevention Laws**
One-Time Capital			
Corrosion Control	$17,183	$12,887	$0
Recurring (7 years)			
Population Surveys	$118	$29	NA
Recurring – Annual			
Corrosion control	$449	$337	$22
Line markers	$153	$76	NA
Damage prevention	$259	$129	$13
Public awareness	$198	$20	NA
MAOP	$0	$0	NA
Design, installation, testing	$0	$0	NA
Emergency plan	$325	$20	NA
Source: PHMSA best professional judgment percentage adjustment (see text) of inflation-adjusted IPAA (2006) cost information.			

3.8.2.4.2 Estimation of Newly-Regulated Mileage

PHMSA currently regulates approximately 11,400 miles of onshore gas gathering pipelines, as shown in **Table 3-87**.

Table 3-87. Currently Regulated Onshore Gas Gathering Infrastructure		
Type A Miles	**Type B Miles**	**Total Miles**
7,844	3,580	11,424
Source: 2014 Gas Gathering Annual Report		

Onshore gas gathering lines are currently unregulated if located in Class 1 locations or Type B in certain Class 2 locations (that is, those locations not meeting the alternative criteria of 49 CFR 192.8(b)(2)). Since PHMSA doesn't collect data on unregulated gas gathering lines, for this analysis, PHMSA relied on comments and data submitted by API[40] to estimate the population of unregulated onshore gas gathering pipelines. API's submittal indicates that an estimated 241,000 miles of currently unregulated onshore gas gathering lines exist within 45 operators' asset portfolios. Those operators also provided information regarding the amount of steel and cathodically protected pipelines. PHMSA estimated that the API estimate represents 70% of total unregulated mileage. Thus, PHMSA estimated that there are a total of 344,086 miles of unregulated gas gathering pipeline infrastructure, 68,749 of which will be newly regulated as Type A, Area 2 (**Table 3-88**).

[40] Letter from Amy Emmert, Policy Advisor, Upstream and Industry Operations, American Petroleum Institute, Re: Pipeline Safety: Safety of Gas Transmission Pipelines (Docket No. PHMSA-2011-0023), October 23, 2012.

Table 3-88. Estimation of Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines			
Type (Class 1 and Class 2)	2012 API Member Estimate[1]	Estimated Unregulated Mileage[2]	Difference[3]
Type A, Area 2 (high stress, ≥ 8")	48,124	68,749	20,625
High stress, < 8"	70,921	101,316	30,395
Type A (assumed < 8")[4]	13,542	19,346	5,804
Low stress, all sizes	108,273	154,676	46,403
Total	**240,860**	**344,086**	**103,226**

1. Source: Letter from Amy Emmert, Policy Advisor, Upstream and Industry Operations, American Petroleum Institute, Re: Pipeline Safety: Safety of Gas Transmission Pipelines (Docket No. PHMSA-2011-0023), October 23, 2012. Data from 45 operators.
2. Calculated as API estimate divided by 0.7, based on PHMSA best professional judgment. Type A Area 2 lines would be newly regulated.
3. Calculated as total mileage minus group 1 operator mileage.
4. PHMSA assumed that any mileage reported as unknown diameter in the API comments is less than 8” in diameter because operators would be aware of their larger high-pressure lines.

Of the Type A, Area 2 mileage that will become regulated, PHMSA assumed that most (97%) is attributable to operators of currently regulated lines, as shown in **Table 3-89**.

Table 3-89. Estimation of Newly Regulated Mileage by Operator Group			
Operator Type	Percent of Total Mileage[1]	Newly Regulated Type A Area 2 Miles	All other Unregulated Miles
No existing regulated lines (group 1)	3%	2,200	8,811
Existing regulated lines (group 2)	97%	66,549	266,526
Total	**100%**	**68,749**	**275,337**

1. Source: PHMSA best professional judgment

3.8.2.4.3 Estimation of Costs

This section details the estimation of the different incremental costs.

<u>Corrosion Control</u>

The API comments indicate that 95% of currently unregulated steel Type A, Class 1 gathering lines have cathodic protection. Based on the larger diameters and higher operating pressures that define Type A, Area 2 pipelines, PHMSA assumed that 100% of the newly-regulated Type A, Area 2 gathering lines are made of steel, and 95% have cathodic protection. **Table 3-90** shows the resulting estimates of mileage needing corrosion control, and the total one-time costs.

Table 3-90. Estimation of One-Time Costs for Corrosion Control for Newly Regulated Gas Gathering Lines				
Operator Type	Newly Regulated Mileage	Mileage without Cathodic Protection[1]	One-Time Corrosion Control Unit Cost per Mile[2]	Total One-Time Corrosion Control Cost
Group 1	2,200	110	$17,183	$1,890,120
Group 2	66,549	3,327	$12,887	$42,882,100

Table 3-90. Estimation of One-Time Costs for Corrosion Control for Newly Regulated Gas Gathering Lines				
Operator Type	**Newly Regulated Mileage**	**Mileage without Cathodic Protection[1]**	**One-Time Corrosion Control Unit Cost per Mile[2]**	**Total One-Time Corrosion Control Cost**
Total	**68,749**	**3,437**	**NA**	**$44,772,220**
1. Calculated as 0.5% of newly regulated mileage. 2. Source: see Table 3-86				

Surveillance

Table 3-91 shows the estimation of periodic costs for right-of-way population surveys (surveillance), on an annualized basis.

Table 3-91. Estimation of Total Costs for Right-of-Way Surveillance for Newly Regulated Gas Gathering Lines				
Operator Type	**Newly Regulated Mileage**	**Periodic Right-Of-Way Surveillance Unit Cost[1]**	**Periodic Surveillance Costs (every 3 years)[2]**	**Annualized Surveillance Cost[3]**
Group 1	2,200	$118	$258,655	$86,218
Group 2	66,549	$29	$1,956,077	$652,062
Total	**68,749**	**NA**	**$2,214,732**	**$738,244**
1. Source: see Table 3-86 2. Unit costs times mileage. 3. Periodic costs divided by three.				

Recurring Costs

Table 3-92 shows the calculation of recurring (annual) costs for corrosion control, line markers, damage prevention, public awareness, and emergency plans.

Table 3-92. Estimation of Recurring Costs for Newly Regulated Gas Gathering Lines							
Mileage Type	**Mileage**	**Unit Costs[2]**					**Total Annual Cost[1]**
		Corrosion Control	**Line Markers**	**Damage Prev.**	**Public Awareness**	**Emergency Plan**	
Operator Group 1							
Total	2,200	$0	$153	$0	$198	$325	$1,485,777
Steel lines; cathodic protection	2,090	$22	$0	$0	$0	$0	$46,933
Steel lines; no cathodic protection	110	$449	$0	$0	$0	$0	$49,403
Operator Group 2							
Total	66,549	$0	$76	$29	$20	$20	$9,669,209
Steel lines; cathodic	63,221	$22	$0	$0	$0	$0	$1,419,721

Table 3-92. Estimation of Recurring Costs for Newly Regulated Gas Gathering Lines							
Mileage Type	Mileage	Unit Costs[2]					Total Annual Cost[1]
		Corrosion Control	Line Markers	Damage Prev.	Public Awareness	Emergency Plan	
protection							
Steel lines; no cathodic protection	3,327	$337	$0	$0	$0	$0	$1,120,832
Total	**68,749**	**NA**	**NA**	**NA**	**NA**	**NA**	**$13,791,875**

1. Calculated as mileage times the sum of applicable unit costs.
2. See Table 3-86

3.8.2.4.4 Total Incremental Compliance Costs for Safety Provisions

Table 3-93 summarizes the present value of one time, periodic, and recurring (annual) costs at seven and three percent discount rates.

Table 3-93. Present Value of Compliance Costs, Gas Gathering Safety Provisions[1]				
Component	Total (7%)	Average Annual (7%)	Total (3%)	Average Annual (3%)
One-time	$44,772,220	$2,984,815	$44,772,220	$2,984,815
Annualized periodic	$7,194,533	$479,636	$9,077,502	$605,167
Annual	$134,408,273	$8,960,552	$169,585,900	$11,305,727
Total	**$186,375,026**	**$12,425,002**	**$223,435,622**	**$14,895,708**

1. Total is present value over 15 year study period; average annual is total divided by 15.

3.8.3 REPEAL THE REPORTING EXEMPTIONS FOR GAS GATHERING LINES

This section addresses the repeal of reporting exemptions for gas gathering lines.

3.8.3.1 Problem Statement

Operators of unregulated onshore gas gathering pipelines are currently exempt from immediate notice and reporting of incidents, reporting of Safety-Related Conditions (SRCs), submittal of annual pipeline summary data, and reporting into PHMSA's National Registry of Pipeline Operators. Two additional types of gas gathering pipelines (gravity lines and lines within the inlets of the Gulf of Mexico) are also exempt from these reporting requirements. PHMSA determined that information about these gathering lines is needed to fulfill PHMSA's statutory and oversight obligations and to evaluate pipeline safety to determine if additional oversight is warranted. The proposed rule would repeal exemptions of previously unregulated gas gathering pipelines to comply with the reporting requirements in 49 CFR Part 191. Collecting this data would allow PHMSA to more fully understand and better assess the safety and environmental risks associated with these pipelines.[41] [42]

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[41] Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety, GAO-12-388, March 2012.

[42] Department of Transportation is Taking Actions to Address Rail Safety, but Additional Actions Are Needed to

3.8.3.2 Assessment of Regulatory Impact

Reports required in the proposed rule are listed in **Table 3-94**.

Table 3-94. Gas Gathering Pipeline Reporting Requirements

Regulation	Description	Timing
191.5	Immediate notice of certain incidents	Upon event
191.15	Incident report	Upon event
191.17	Annual report (i.e., pipeline summary data)	Annually
191.22(a)	Operation identification request	Once
191.22(c)	Notification of changes	Upon event
191.23	Safety-related condition report	Upon event

Validation of operator identification (OPID) numbers through the National Registry of Pipeline Operators [(§ 191.22(b)] and filing of offshore pipeline condition reports (§ 191.27) are expired requirements and would not be applicable to newly-regulated gathering lines. However, the other reporting requirements under 49 CFR Part 191 applicable to gas transmission pipelines would selectively apply, as described below.

PHMSA estimated that a total of approximately 344,000 miles of gathering lines would be subject to either some or all of the reporting requirements of § 191.5, § 191.15, § 191.17, § 191.22(a) and (c), and § 191.23, including the accompanying administrative provisions of Part 191. The new Type A, Area 2 lines subject to selected safety provisions of PHMSA's regulations would be subject to all of the reporting provisions. The remaining gathering lines not subject to Part 192 would be subject to a set of selected reporting provisions as shown in **Table 3-95**.

Table 3-95. Proposed Reporting Requirements

Regulation	Description	Type A, Area 2 Lines	All Other Currently Unregulated Lines
191.5	Immediate Notice of certain incidents	√	√
191.15	Incident Reports	√	√
191.17	Annual Reports (i.e., pipeline summary data)	√	√
191.22(a)	OPID Request	√	√
191.22(c)	Notification of Changes	√	NA
191.23	Safety-Related Condition Reports	√	NA
NA = not applicable			

Operators of currently regulated lines already have the processes, procedures, forms, and training to readily accommodate reporting. However, the actual reporting would result in additional costs. Newly-regulated operators under 49 CFR Part 191 would require new procedures and processes to comply, incurring costs.

3.8.3.3 Analysis Assumptions

Reporting requirements are annual, one-time, or event-driven. Filing an annual report would be a new requirement for operators with no previously regulated gas pipelines, but not for

Improve Pipeline Safety, GAO-14-667, August 2014 operators of existing pipelines regulated under Part 192 (although their reported numbers would need to be revised due to the additional gathering line mileage that would be reported).

For the National Registry reporting, all newly-regulated operators would need to file a one-time OPID Request. Operators with existing regulated lines already have OPIDs assigned, and the proposed rule includes a notification of change exemption for those gaining 50 miles or more of newly-regulated lines to report as a result of the proposed rule.

3.8.3.4 Estimation of Costs

This section develops estimates of cost by provision.

3.8.3.4.1 Type A, Area 2 and All Other Currently Unregulated Onshore Gathering Lines

Newly-regulated operators (group 1) would incur incremental compliance costs to create new procedures, processes, and guidance for each of the newly required reports. Operators with existing regulated lines (group 2) would only need to expand existing reporting mechanisms at less cost. For both groups of operators, there would be additional compliance costs associated with the actual submission of the reports, either on an annual or on a per-event basis. Estimated unit costs to file reports on a per-operator, per-year, or per-event basis for the various reporting provisions of the proposed rule are summarized in **Table 3-96**. PHMSA estimated these costs by estimating the amount of time involved for each task associated with the individual reporting item multiplied by typical hourly rates for the various types of operator staff positions involved.

Table 3-96. Estimates of Unit Cost for Reporting Provisions (Per report)

Component	Group 1 One-Time	Group 1 Per Event	Group 2 One-Time	Group 2 Per Event	Group 1,2 Annual
Immediate notice	$1,300	$100	$100	$100	NA
Incident report	$2,580	$1,400	$180	$1,400	NA
SRC report	$2,900	$340	$180	$340	NA
Annual report	$1,780	NA	$620	NA	$280
OPID request	$520	NA	NA	NA	NA
Notification of change	$980	$85	$180	$85	NA

Source: PHMSA best professional judgment
Group 1 = operators without pre-existing lines.
Group 2 = operators with pre-existing regulated lines.
See Table 3-98 for reporting requirements applicable to Group 1 and Group 2 mileage

3.8.3.4.2 Gravity Lines and Lines within the Inlets of the Gulf of Mexico

The proposed rule would repeal the reporting exemption for gravity lines and lines within the inlets of the Gulf of Mexico. These types of gathering lines are rare, and total mileage is insignificant compared to the very large amount of onshore gathering line mileage. Also, it is very likely that most such lines exist within the asset portfolios of operators of onshore gathering lines accounted for in this analysis. As a result, the cost to implement these four reporting provisions for these lines is negligible.

3.8.3.4.3 Summary of Operators and Mileages Impacted by the Reporting Provisions

Based on the analysis of mileages by operator group included in Section 3.8.2, the operator groups and the mileages to which the various reporting provisions apply are summarized in **Table 3-97** and **Table 3-98**.

Table 3-97. Summary of Mileages by Operator Group

Type A, Area 2 Lines		All Other Currently Unregulated Lines[1]	
Group 1	Group 2	Group 1	Group 2
2,200	66,549	8,811	266,526

Group 1 = operators without existing regulated lines.
Group 2 = operators of existing regulated lines.
1. Total estimated currently unregulated mileage minus Type A, Area 2 currently estimated unregulated.

Table 3-98. Reporting Requirements by Operator Group

Regulation	Description	Type A, Area 2 Lines		All Other Currently Unregulated Lines		Timing
		Group 1	Group 2	Group 1	Group 2	
191.5	Immediate notice	√	√	√	√	Upon event
191.15	Incident report	√	√	√	√	Upon event
191.17	Annual report	√	√	√	√	Annually
191.22(a)	OPID request	√	√	√	√	Once
191.22(c)	Notification of changes	√	√	NA	NA	Upon event
191.23	Safety-related condition report	√	√	NA	NA	Upon event

Group 1 = operators without existing regulated lines
Group 2 = operators of existing regulated lines
NA = not applicable

3.8.3.4.4 One-time Compliance Costs for Reporting Provisions

All Type A, Area 2 gathering lines and other currently unregulated gathering lines would incur one-time compliance costs for reporting. One-time costs would be greater for operators in group 1 who currently are not regulated under Part 191. The numbers of operators with and without pre-existing regulated lines were estimated for each operator group, since the reporting requirements differ.

Operators in group 2 are already subject to Part 191 reporting requirements. PHMSA assumes that each of these 292 operators (as established in section 3.8.B) would incur some level of one-time compliance costs. PHMSA assumes that the 45 large operators that contributed to API's submittal would incur the larger one-time costs associated with all reporting provisions. Because many of the remaining 247 operators are large or medium size operators, PHMSA assumes that 90% of them (222) would also be subject to all reporting provisions. PHMSA assumes the remaining operators (25) would be subject to fewer reporting provisions.

The operators in group 1 are assumed to have only a small amount of reported mileage, consistent with the assumption made in Section 3.8.2. Therefore, it is likely that many of them do not operate lines Type A, Area 2 lines. For purposes of this analysis, PHMSA assumes that all reporting provisions would apply to half (38) of the operators in group 1, and fewer reporting provisions would apply to the other 38 operators.

Applying the unit cost estimates to the numbers of operators, the total one-time compliance costs are shown in **Table 3-99**.

Table 3-99: One Time Compliance Costs of Gathering Line Reporting Requirements

Category	Miles	Cost per Mile	Total One-Time Costs
Type A, Area 2 Lines[1]			
Group 1	2,200	$173.77	$382,280
Group 2	66,549	$5.06	$336,420
Subtotal	68,749	NA	$718,700
All Other Currently Unregulated Lines[2]			
Group 1	8,811	$26.65	$234,840
Group 2	266,526	$0.08	$22,500
Subtotals	275,337	NA	$257,340
Total	**344,086**	**NA**	**$976,040**

Source: PHMSA best professional judgment
Group 1 = operators without existing regulated lines
Group 2 = operators of existing regulated lines
1. Immediate notice, incident, SRC, annual, OPID request, notification of change reporting.
2. Immediate notice, incident, annual, and OPID request reporting.

3.8.3.4.5 Recurring Compliance Costs for Reporting Provisions

Annual reports would be required for each operator. The first-year costs would be significantly higher since in subsequent years operators would only report mileage that has changed and/or been added. Higher first-year costs for annual reporting are accounted for in the one-time costs estimated in Section 3.8.3.4.4 above. This section addresses only the annual recurring costs.

Immediate notice, incident reporting, and SRC reporting costs are driven by events. To estimate these recurring reporting costs, PHMSA estimated the number of triggering events.

<u>Incidents Reporting</u>
PHMSA estimated the number of reportable incidents for which incident reporting would be required, based on a predicted incident rate established in Section 6.2.3. For Type A, Area 2 lines subject to Part 192, PHMSA expects the incident rate to decrease over time due to the influence of implementing the applicable safety regulations. The other currently unregulated gathering lines would not be subject to Part 192 so PHMSA assumed that the baseline incident rate would remain constant. PHMSA estimated the costs for immediate notice and incident reports using these incident rates. **Table 3-100** summarizes the results.

Table 3-100. Cost of Incident Reporting for Newly Regulated Gas Gathering Pipelines

Year	Incidents per 1,000 Miles[1]	Cost per Incident[2]	Annual Cost per 1,000 Miles	Costs per Year[3]
1	0.2	$1,500	$300	$20,625
2-5	0.1	$1,500	$150	$10,312
6-15	0.04	$1,500	$60	$4,125

Table 3-100. Cost of Incident Reporting for Newly Regulated Gas Gathering Pipelines				
Year	**Incidents per 1,000 Miles[1]**	**Cost per Incident[2]**	**Annual Cost per 1,000 Miles**	**Costs per Year[3]**
1. Source: PHMSA best professional judgment. See benefits analysis. 2. Table 3-86, $1,400 for incident report, $100 for immediate notification per incident 3. Cost per 1,000 miles × 68.749 thousand Type A Area 2 miles.				

<u>SRC Reporting</u>

SRC reporting is only required for operators of Type A, Area 2 gathering lines. Historically, SRC reports are filed infrequently, particularly for the relatively small amount of gathering mileage currently regulated. Based on historical reporting levels, PHMSA estimated approximately 0.23 SRC reports each year per 1,000 miles of gathering lines. PHMSA assumed this rate would remain relatively constant. **Table 3-101** show the calculation of annual compliance costs for reporting SRCs.

Table 3-101. Annual Costs for Safety Related Condition Reports			
Reports per 1000 Miles[1]	**Unit Cost per Report[2]**	**Cost per 1000 Miles[3]**	**Total Annual Costs[4]**
0.23	$340	$78.20	$5,376
1. Source: Estimated based on historical reporting levels 2. Source: PHMSA best professional judgment 3. Calculated as reports times unit cost. 4. Calculated as cost per 1000 miles times thousands of Type A Area 2 miles (Table 3-96).			

<u>Annual Reporting</u>

All operators would be required to report annually, and reporting costs are estimated to be the same for all operators. Operator numbers established in Section 3.8.C.4.4 are used to estimate annual recurring costs. Since these lines are all exempt from 49 CFR Part 192, Subpart O Integrity Management Program (IMP) requirements, portions of the annual report associated with IM program data would not be required by any of these operators for their gathering lines (newly-regulated or not). **Table 3-102** shows the costs for filing annual reports.

Table 3-102. Costs for Annual Reporting			
Group	**Miles**	**Annual Cost Per 1000 Miles**	**Total Annual Costs**
Type A Area 2	68,749	$1,242	$85,400
All other regulated	275,337	$64	$17,640
Total	**344,086**	**NA**	**103,040**

<u>National Registry Reporting</u>

Operators of existing regulated gathering lines already have OPID numbers. Therefore, only operators with no regulated lines incur costs for requesting an OPID. OPIDs remain in the National Registry until the operator requests a retirement. Therefore, costs are included in the one-time compliance costs covered in Section 3.8.C.4.4, for newly-regulated operators (i.e., operator group 1).

The notification of change provision of the National Registry drives incremental compliance costs for reporting and would only apply to operators of Type A, Area 2 lines. Operators are required to report whenever an operator experiences one of the eight changes specifically defined in § 191.22(c).

Because notification of change is a relatively new regulation, very little historical data exists. However, this particular sector of the pipeline industry is undergoing a disproportionate amount of change, particularly with new construction, and it is likely that some amount of reporting would occur. The primary changes particularly applicable are: new pipeline construction of 10 miles or more; acquisition or divestiture of 50 miles or more of pipelines; and, a change in the entity operating the pipelines or administering a regulated safety program. For illustration, PHMSA assumed that 30% (92) of the 305 operators of Type A, Area 2 lines would construct 10 or more miles of gathering line each year and that 10% (30) have a reportable acquisition, divestiture, merger, or operating entity change each year. Accordingly, **Table 3-103** shows the total annually recurring compliance costs estimated for change reporting.

Table 3-103. Recurring Incremental Compliance Costs for National Registry Reporting

Operator Group	Number of Operators[1]	Annual Costs per Operator[1]	Total Annual Costs
Constructing 10 or more miles of pipelines	92	$85	$7,820
Acquisition, divestiture, merger, and entity changes	31	$85	$2,635
Total	**123**	**$85**	**$10,455**

1. Source: PHMSA best professional judgment

3.8.3.4.6 Total Incremental Compliance Costs for Reporting Provisions

Applying the costs from sections 3.8.3.4.4 through 3.8.3.4.5 to the 15-year study period yields a total incremental cost of compliance for the reporting provisions of Topic Area 8. **Table 3-104** and **Table 3-105** show the present value results.

Table 3-104. Present Value of Recurring Reporting Costs

Provision	7% Discount Rate		3% Discount Rate	
	Total[1]	Average Annual[2]	Total[1]	Average Annual[2]
Incident reporting	$77,657	$5,177	$90,219	$6,015
SRC reporting	$52,393	$3,493	$66,105	$4,407
Annual reporting	$842,180	$56,145	$1,130,046	$75,336
National Registry Reporting	$101,889	$6,793	$128,555	$8,570
Total	**$1,074,119**	**$71,608**	**$1,414,926**	**$94,328**

1. Represents 15-year study period.
2. Total divided by 15.

Table 3-105. Present Value of Reporting Provision Costs

Type of Provision	7% Discount Rate		3% Discount Rate	
	Total	Average Annual	Total	Average Annual
Recurring[1]	$1,074,119	$71,608	$1,414,926	$94,328
One-time[2]	$976,040	$65,069	$976,040	$65,069
Total	**$2,050,159**	**$136,677**	**$2,390,966**	**$159,398**

1. Source: See Table 3-83.
2. Source: See Table 3-75.

3.9 SUMMARY OF COSTS

Table 3-106 summarizes the estimated present value of compliance costs by Topic Area. PHMSA also estimated the climate-related costs associated with the methane releases associated with compliance. **Table 3-107** shows the combined results. **Table 3-108** shows a breakout of compliance costs by subtopic are for Topic Area 1.

Table 3-106. Summary of Present Value Compliance Costs (Millions 2015$)[1]

Topic Area	7% Discount Rate		3% Discount Rate	
	Total	Average Annual	Total	Average Annual
1	$267.3	$17.8	$330.1	$22.0
2	$32.7	$2.2	$19.4	$1.3
3	$10.0	$0.7	$12.4	$0.8
4	$94.8	$6.3	$118.5	$7.9
5	$1.1	$0.1	$1.1	$0.1
6[2]	$2.9	$0.2	$2.9	$0.2
7	$0.4	$0.0	$0.4	$0.02
8	$188.4	$12.6	$225.8	$15.1
Total	**$597.5**	**$39.**8	**$710.5**	**$47.**4

1. Total present value over 15 study period; average annual calculated by dividing total by 15.
2. PHMSA analyzed this component with a pre-statutory baseline, however most operators are expected to be in compliance with the Act

Table 3-107. Summary of Present Value Total Costs (Millions 2015$)[1]

Component	7% Discount Rate		3% Discount Rate	
	Total	Average Annual	Total	Average Annual
Compliance costs	$570.0	$38.0	$683.1	$45.5
Social cost of methane[2]	$27.5	$1.8	$27.5	$1.8
Total	**$597.5**	**$39.8**	**$710.5**	**$47.4**

1. Total present value over 15 study period; average annual calculated by dividing total by 15.
2. Based on 3% value. See Appendix B for discussion of other estimated values.

Table 3-108. Breakdown of Present Value Costs, Topic Area 1 (Millions 2015$)

Subtopic Area	7% Discount Rate		3% Discount Rate	
	Average Annual	Total	Average Annual	Total
Re-establish MAOP: HCA > 30% SMYS	$0.5	$7.4	$0.60	$9.0
Re-establish MAOP: Inadequate Records	$8.0	$120.3	$9.8	$147.2
Integrity Assessment: Non-HCA	$6.3	$94.9	$7.9	$119.2
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	$3.0	$44.7	$3.6	$54.7
Total	**$17.8**	**$267.3**	**$22.0**	**$330.1**

HCA = high consequence area
MAOP = maximum allowable operating pressure
SMYS = specific minimum yield strength

4. ANALYSIS OF BENEFITS

This section provides detailed analysis of benefits by topic area. PHMSA estimated the value of avoiding fatalities, injuries, property damage, and environmental damage associated with pipeline incidents preventable through the proposed regulatory requirements.

4.1 TOPIC AREA 1: RE-ESTABLISH MAOP, VERIFICATION OF MATERIAL PROPERTIES, AND INTEGRITY ASSESSMENT AND REMEDIATION FOR SEGMENTS OUTSIDE HCAS

The primary quantifiable benefit of the proposed requirements is the potential number of pipeline incidents that may be averted by conducting integrity assessments and repairs on pipeline segments located outside of HCAs that have not been previously assessed or that are assessed as part of re-establishing MAOP. Therefore, the benefits are based on the identification of defects from integrity assessments and leaks and failures during pressure testing assessments. Both conditions would require prompt repair prior to returning the line to service (or be addressed via other measures such as near-term pressure reductions).

4.1.1 ANALYSIS ASSUMPTIONS

PHMSA quantified and monetized the benefit of avoiding incidents assuming that defects or pressure test failures represent imminent or near-term integrity threats that could lead to future reportable pipeline incidents and associated costs, When monetizing the benefit, PHMSA assumed that the benefit is realized during the same year as the assessment is conducted.

In the case of pressure test failures, the defect must be repaired before the test can be successfully concluded. In the case of immediate conditions, the repair must be made immediately (typically within five days) or else the operating pressure must be reduced (in order to preclude failure) until the defect can be repaired. For non-immediate conditions, the proposed rule would require an operator to evaluate the defect and reduce pressure if an immediate hazard is present, and complete repairs as soon as feasible. Therefore, since the risks of an incident have generally been eliminated at the time of detection, PHMSA assumed that benefits from avoided incidents accrue in the year of detection.

PHMSA does not have specific data with which to quantify the percent of defects which would have resulted in failure and thus the safety benefits. PHMSA used its professional judgment to estimate this percentage by method of discovery (assessment method).

4.1.2 ANALYTICAL APPROACH

PHMSA quantified and monetized benefits using the following equation:

Miles Assessed x Incidents Averted Rate x Average Incident Consequences

Section 3.1 provides the mileage estimates for each sub-topic area in. Further, the mileage estimates are broken down by class location and by type of assessment. The sections below describe the estimation of incidents averted and consequences.

In addition, PHMSA estimated cost-savings as described in Section 4.2.2.3.

4.1.2.1 Incidents Averted Rate

PHMSA estimated the rate of incidents averted by estimating and multiplying the defect discovery rate per mile by test method by the percent of defects that would have resulted in an incident in the absence of the rule (i.e., not detected and repaired). PHMSA used data from the hazardous liquid and gas transmission annual reports shown in Appendix C in estimating defect discovery rates. **Table 4-1** shows the assumed rates for different categories of pipe affected under Topic Area 1.

Table 4-1. Summary of Estimated Defect Discovery Rates (per Mile)

Requirement	Defect Discovery Rate	Description
Integrity verification, previously assessed pipe (HCA)[1]	ILI, DA: 0.05 (immediate); 0.38 (scheduled) PT: 0.03	Represents difference between hazardous liquid and gas transmission discovery rates (see Appendix C) since proposed gas transmission requirements resemble existing requirements for hazardous liquid pipe.
Non-HCA integrity verification and MCA assessments of previously unassessed pipe[2]	ILI, DA: 0.10 (immediate); 0.49 (scheduled) PT: 0.03	Represents hazardous liquid baseline discovery rate since proposed repair criteria and assessment requirements are similar.

1. Re-establishing MAOP for previously untested pipe and pipe for which records are inadequate.
2. Includes requirements addressing previously untested pipe, inadequate records, and integrity assessments outside of HCAs.

Table 4-2 provides PHMSA's estimates of defects discovered that would have resulted in failure (operator would not have identified and repaired) based on considerations regarding these discoveries. For example, immediate repair criteria represent a calculated failure pressure less than 1.1 times operating pressure or pipe wall loss greater than 80% loss. Other factors to consider are overpressure protection set at 1.04 times MAOP; a safety factor of 6% or less to account for combined stresses; and that the operator has 180 days for ILI result evaluation prior to the ILI results being an immediate discovery. Therefore, based upon a safety margin of less than 6%, a failure rate between 3% and 12.5% is reasonable. Pressure tests are very effective at finding defects (wall loss, dents, or cracking) that would not otherwise have been abated. PHMSA invites comments on these estimates.

Table 4-2. Estimated Percent of Defects Which Would Have Resulted In Failure

Method	Low	High
Inline and direct assessment (immediate repair)	3.0%	12.5%
Inline and direct assessment (scheduled repair)	0.3%	0.5%
Pressure test	33.3%	50.0%

Source: PHMSA best professional judgment considering that immediate repair criteria represent a calculated failure pressure less than 1.1 times operating pressure or pipe wall lost greater than 80% loss, and other factors including overpressure protection, safety margin for combined stresses, and 180 days for results to represent immediate discovery. Pressure tests are very effective at finding defects (wall loss, dents, or cracking) that would not otherwise have been abated.

Multiplying the mileage assessed via each method (see Section 3.1) by the defect discovery rate and percent that would have resulted in failure results in the estimates of incidents averted shown in **Table 4-3**.

Table 4-3. Estimated Incidents Averted, Topic Area 1								
Scope	Mileage		HCA %		Incidents Averted[1]			
	ILI and DA	PT	HCA	Non-HCA	ILI and DA, Immediate	ILI and DA, Scheduled	PT	Total
HCA >30% SYMS	793	116	100%	0%	1.2-4.9	0.9-1.5	1.3-2	3.4-8.4
HCA; Class 3 and 4 non-HCA	3,686	678	42%	58%	8.9-37.2	4.9-8.1	7.8-11.8	21.6-57.1
MCA Class 3 and 4; MCA Class 1 and 2 (piggable)	7,129	250	0%	100%	22.1-92.2	10.4-17.3	2.9-4.4	35.4-113.9
HCA 20-30% SMYS; non-HCA Class 3 and 4; MCA Class 1 and 2 (piggable)	2,647	170	9%	91%	7.8-32.6	3.8-6.3	2-3	13.5-41.8
Total	**14,255**	**1,213**	**NA**	**NA**	**40.1-166.9**	**19.9-33.2**	**14.0-21.2**	**74.0-221.3**

DA = direct assessment
HCA = high consequence area
ILI = inline inspection
MCA = moderate consequence area
PT = pressure test
SMYS = specified minimum yield strength
1. Based on multiplying estimated mileage by defect discovery rate and range of percentage of defects that would have resulted in failure absent the proposed rule.

4.1.2.2 Average Incident Consequences

Operators identify the cause attributable to an incident on incident reports submitted to PHMSA. Some incidents might not be averted by integrity assessments and the management of time-dependent threats. Incidents due to hurricanes or other extreme weather events, or third-party damage, in which the pipe fails at the time of the event would not necessarily be averted by the requirements in the proposed rule under Topic Area 1. **Table 4-4** summarizes causes preventable by integrity assessments; Appendix E summarizes the subset of gas transmission incidents attributable to these causes. (Note that the list of causes was revised in 2010.) PHMSA significantly expanded the information required in incident reporting in 2010. For some of the topic areas PHMSA used only incident data since 2010; prior to 2010 specific information is not available that would support an effective analysis of those topic areas.

Table 4-4. Causes of Incidents Detectable by Modern Integrity Assessment Methods	
2003-2009	**2010-present**
External corrosion	External corrosion
Internal corrosion	Internal corrosion
Rupture of previously damaged pipe	Previous damage due to excavation activity
Body of pipe; pipe seam weld	Original manufacturing-related (not girth weld or other welds formed in the field)
Joint; butt weld; fillet weld	Construction-, installation-, or fabrication-related
NA	Environmental cracking-related
Source: PHMSA Incident Report Form	

The data summarized in Table E-2 was reported to PHMSA in operator incident reports; except that publicly available information was used to estimate the consequences of the 2010 San Bruno incident (see Appendix D). The specific incident data is also provided in Appendix E. For comparison, incident data for gas transmission incidents for all causes is summarized (Table E-1). However, the subareas within Topic Area 1 analyze requirements that are focused on selected locations, such as HCAs, MCAs, or Class 3 or 4 locations. PHMSA filtered the data to estimate benefits for each subarea as follows:

Table 4-5 summarizes the average incident consequences for these groups of incidents.

Table 4-5. Estimated Average Per Incident Consequences, Topic Area 1 (2015$)

Subtopic Area	HCA	Non-HCA
MAOP verification for segments within HCA	$23,408,790[1]	NA
MAOP verification for segments with inadequate records within HCA and Class 3 and Class 4	$23,408,790[1]	147,800[2]
Integrity assessments for segments within MCA in Class 3 and Class 4, and Class 1 and Class (piggable)	N/A[1]	$1,085,660[3]
MAOP verification for segments within HCA (operating between 20%-30% SMYS) and MCA (Class 3 and Class 4; Class 1 and Class 2 piggable)	$23,408,790[1]	$1,085,660[3]

Source: PHMSA Gas Transmission Incident Reports summarized in Tables E-3 through E-6.
HCA = high consequence area
MCA = moderate consequence area
MAOP = maximum allowable operating pressure
NA = not applicable
PT = pressure test
SMYS = specified minimum yield strength
1. Based on HCA incidents from 2003-2015 (see Table E-3).
2. Based on Class 3 and 4 non-HCA incidents from 2003-2015 (see Table E-8).
3. Based on estimate of incidents that may represent MCA incidents (see Table E-4).

There are several economic consequences of pipeline incidents that are not covered in PHMSA's data, and hence are not included in this benefit-cost analysis. In particular, even minor pipeline incidents cause an interruption of service that may last a few days or may occasionally (as in the case of San Bruno) be permanent. There is a private cost to the pipeline operator in the form of lost tolls, a loss to shippers in the form of deferred shipment, storage, or lost or deferred gas production, and potentially a loss to end users in the form of having to make unplanned alternative supply arrangements for some period of time. These costs are incident-, time- and location-specific, and spread across multiple actors, and are difficult to estimate.

In addition, pipeline incidents may generate emergency response and other social costs borne by local communities and that are not captured in operator's cost estimates filed with the incident report. Except in the case of San Bruno, emergency response costs have not been included in the consequences of incidents.

Historical data establish that incidents are often relatively low in cost, but that occasional high cost incidents have occurred and that infrequent, extremely high cost incidents have also occurred. High consequence incidents have also occurred across Class locations; the second most consequential incident since PHMSA has been keeping records (Carlsbad, New

Mexico, in 2000) occurred in a Class 1 location.[43] This incident resulted in the death of 12 people camping under a concrete-decked steel bridge that supported the pipeline across the river and an estimated $1 million in property and other damages.

4.1.2.3 Cost Savings

With respect to the statutory requirement in the Act, 23, Congress required DOT to require that pipeline operators conduct a records verification to ensure that the records accurately reflect the physical and operational characteristics of the pipelines and confirm the established MAOP. The results of that action indicated that problems similar to those that contributed to the San Bruno incidents are more widespread than previously believed. As a result, the proposed rule would establish consistent standards by which operators would correct these issues in a way that is more cost effective than the current regulations would require (which could require more extensive destructive testing, pressure testing, and/or pipe replacement).

PHMSA estimated the cost savings to operators associated with the Section 23(c) mileage. Existing regulatory requirements [§192.107(b)] related to bad or missing records would be more costly for operators to achieve compliance. Currently, in order to maintain operating pressure, operators must excavate the pipeline at every 10 lengths of pipe (commonly referred to as joints) in accordance with section II-D of Appendix B of Part 192 (as specified in §192.107(b)), do a cutout, determine material properties by destructive tensile test, and repair the pipe. The process is similar to doing a repair via pipe replacement. PHMSA developed an average for performing such a cutout material verification ($75,000) by reviewing typical costs to repair a small segment of pipe by pipe replacement. The estimate accounts for various pipe diameters and regional cost variance. PHMSA assumed each joint is 40 feet long; ten joints are 400 ft. The number of cutouts required by existing rules is therefore the miles subject to this requirement multiplied by 5,280/400 (13.2). Therefore, the average cost to comply with these requirements is approximately $990,000 per mile.

The proposed rule would allow operators to perform a sampling program that opportunistically takes advantage of repairs and replacement projects to verify material properties at the same time. Over time, operators will collect enough information gain significant confidence in the material properties of pipe subject to this requirement. The proposed rule nominally targets conducting an average of one material documentation process per mile. In addition, operators would be allowed to perform nondestructive examinations, in lieu of cutouts and destructive testing, when the technology provides a demonstrable level of confidence in the result.

Table 4-6 provides a summary of the cost savings.

Table 4-6. Estimation of Average Annual Cost Savings of Proposed Material Documentation Requirements[1]

Component	Average Annual Cost (Millions 2015$)
Existing requirements (cutouts) [2]	$288.0
Proposed rule (IVP)[3]	$14.3
Cost savings (over 15 years)	$273.7

[43] NTSB/PAR-03/01- http://www.ntsb.gov/investigations/AccidentReports/Reports/PAR0301.pdf

Table 4-6. Estimation of Average Annual Cost Savings of Proposed Material Documentation Requirements[1]	
Component	**Average Annual Cost (Millions 2015$)**
IVP = integrity verification program NA = not applicable 1. Based on 291 miles of pipe for which there are incomplete, missing, or inadequate records to substantiate maximum allowable operating pressure as indicated in the 2014 Gas Transmission Annual Report. The proposed requirements would provide comparable safety with a pressure test at or above 1.25 times maximum allowable operating pressure and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods. 2. Calculated as mileage multiplied by 13.2 cutouts per mile and $75,000 per cutout. 3. Average annual cost to re-establish MAOP for segments with inadequate MAOP records using methods permitted in the proposed rule (see Section 3.1.5).	

4.1.3 ESTIMATION OF BENEFITS

Table 4-7 shows the estimated safety benefits estimates for each sub-topic area. **Table 4-8** shows the estimated cost savings.

Table 4-7. Present Value of Safety Benefits, Topic Area 1 (Millions $2015)

	7% Discount Rate		**3% Discount Rate**	
Component	**Total[1]**	**Average Annual[2]**	**Total[1]**	**Average Annual[2]**
MAOP verification for segments within HCA	$52-$128	$3-$9	$66-$162	$4-$11
MAOP verification for segments with inadequate records within HCA + Class 3 & 4	$140-$371	$9-$25	$177-$468	$12-$31
Integrity assessments for segments within MCA in Class 3&4 and Class 1&2 (piggable)	$25-$80	$2-$5	$32-$101	$2-$7
MAOP verification for segments within HCA(20%-30% SMYS) + MCA (Class 3&4, Class 1&2 piggable)	$28-$87	$2-$6	$36-$110	$2-$7
Total	**$245-$667**	**$16-$44**	**$310-$842**	**$21-$56**

MAOP = maximum allowable operating pressure
1. Present value over 15-year study period.
2. Total divided by 15.

Table 4-8. Present Value of Cost Savings Benefits, Topic Area 1 (Millions, 2015$)[1]

7% Discount Rate		**3% Discount Rate**	
Total	**Average Annual**	**Total**	**Average Annual**
$2,668	$178	$3,366	$224

MAOP = maximum allowable operating pressure
1. Associated with MAOP verification for segments for which records are inadequate within high consequence area and Class 3 and 4 locations. Material verification cost savings would provide comparable safety with a pressure test at or above 1.25 times MAOP and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods. Total is present value over 15-year study period; average annual is total divided by 15.

4.1.4 ADDITIONAL BENEFITS NOT QUANTIFIED

The benefit analysis is focused on the adverse safety consequences averted from postulated incidents by detecting and repairing latent or future defects associated in pipeline segments. The assessment and repair of the pipeline serves to maintain the pipeline in better condition before serious degradation could occur. By requiring assessment on a periodic basis and the timely repair of pipeline defects, the proposed rule is expected to significantly contribute to the extension of the useful life of the pipeline, which represents a significant long term economic benefit not quantified in this analysis.

In addition, avoidance of future incidents results in fewer unplanned system outages, operating pressure restrictions, and potential service curtailments, which would result in future lost revenue for operators, which PHMSA did not quantify.

4.2 TOPIC AREA 2: IMP PROCESS CLARIFICATIONS

This section addresses benefits from the proposed integrity management program process clarifications. In general, PHMSA used the same analytical approach as for Topic Area 1 except that incident averted rate applies to the number of applicable defects in HCAs repaired sooner.

4.2.1 ANALYSIS ASSUMPTIONS

As described in section 3.2.4.1, PHMSA estimated that approximately 210 pipeline defects per year located in HCAs would meet the new criteria for one-year conditions and be repaired more promptly than currently required.

4.2.2 ESTIMATION OF BENEFITS

PHMSA does not have specific data with which to quantify the estimated safety benefit of sooner repairs. However, the total annual cost of accelerated repairs is relatively low. The estimated cost varies based on the rate at which the cost difference between the baseline costs and accelerated costs are discounted as described in Section 3.2. Based on the average incident consequences in HCAs (see Appendix E), between 0.10 (7% scenario) and 0.05 (3% scenario) incidents would need to be averted annually for monetized benefits to equal estimated costs (i.e., between 1-2.2 incidents over the 15-year study period in both scenarios). **Table 4-9** shows these results.

Table 4-9. Breakeven Analysis, Topic Area 2

Scenario	Annual Cost[1]	Average HCA Incident Consequences[2]	Break-Even Number of Incidents per Year[3]
7% interest rate	$3,350,528	$23,408,790	0.14
3% interest rate	$1,575,790	$23,408,790	0.07

1. See Table 3-43. Annual cost represents the change in time value of money of expedited repairs for the given interest rate
2. See Table E-3.
3. Calculated as annual cost divided by average incident consequences.

4.2.3 ADDITIONAL BENEFITS NOT QUANTIFIED

Clarifications to the threat identification processes, baseline assessment methods, preventive and mitigative measures, and periodic evaluations and assessments are beneficial to the continuous improvement of integrity management. Additionally, these clarifications emphasize the functions that must be accomplished, elaborate on the elements of effective processes, and clearly articulate PHMSA's expectations in these areas. The proposed rule adds language from national consensus standards in the areas of validating risk models and conducting integrity assessments and remediating anomalies. PHMSA expects that emphasizing and clarifying these aspects of IM by incorporating them into the rule text may improve operator implementation of existing IM requirements. Enhancing implantation of IM would lead to further unquantified safety and environmental benefits and improved public confidence in the safe operation of new and existing gas transmission pipelines.

4.3 TOPIC AREA 3: MANAGEMENT OF CHANGE PROCESS IMPROVEMENT

This section provides analysis of benefits from improving management of change. The analytical approach is valuing the estimated incidents averted per year by the estimated average cost based on historical data.

4.3.1 ANALYSIS ASSUMPTIONS

PHMSA does not have specific data with which to quantify the estimated safety benefit of a programmatic or process oriented management system such as management of change. However, some extremely high consequence incidents have occurred in recent years in which inadequate change control, including field change control, contributed to the incident, including high-visibility incidents at San Bruno, CA, Bellingham WA (hazardous liquid pipeline) and Walnut Creek, CA (hazardous liquid pipeline). For example, the San Bruno incident was caused from a pup piece (a short piece of pipe) that was not qualified pipe. This pup piece was apparently inserted during a field change and was not properly approved or documented. An effective management of change process would prevent such erroneous substitutions of substandard material during pipeline construction. Management of change affects all aspects of pipeline design, construction, operation, and maintenance. For illustration, PHMSA assumed that one incident per year would be averted by the proposed management of change regulation.

4.3.2 ESTIMATION OF BENEFITS

Table 4-10 and **Table 4-11** show the calculation of safety benefits from Topic Area 3.

Table 4-10. Calculation of Safety Benefits, Topic Area 3 (Millions 2015$)

Incidents Averted per Year[1]	Average Cost per Incident[2]	Annual Benefits[3]
1	$0.8	$0.8

1. Source: PHMSA best professional judgment
2. See Table E-1
3. Calculated as incidents averted × average cost per incident.

Table 4-11. Present Value of Benefits, Topic Area 3 (Millions 2015$)

7% Discount Rate		3% Discount Rate	
Total[1]	Average Annual[2]	Total[1]	Average Annual[2]
$8.2	$0.5	$10.3	$0.7

1. Present value over 15-year study period.
2. Total divided by 15.

4.4 TOPIC AREA 4: CORROSION CONTROL

This section addresses benefits from corrosion control using the same analytical approach as for Topic Area 3.

4.4.1 ANALYSIS ASSUMPTIONS

This section describes the assumptions related to surveys, interference currents, and internal corrosion controls.

External Corrosion Coating Surveys and Close Interval Surveys

From 2010 through 2013, operators reported 31 reportable onshore incidents caused by external corrosion. For 20 of those incidents, operators reported the most recent annual cathodic protection (CP) survey date. Out of those 20 incidents, operators reported close interval survey (CIS) dates at or after the CP survey date for only 2 of the incidents. Requiring CIS to further investigate and correct CP deficiencies would reduce external corrosion incidents. The proposed regulations are expected to reduce but not completely eliminate failures caused by external corrosion. PHMSA does not have specific data to estimate the safety benefits of this provision. For illustration, PHMSA assumed that the proposed rule would avert approximately four incidents per year.

In addition to reducing external corrosion incidents caused by coating failures, the rule will also produce economic benefits in the form of reduced corrosion repairs necessary to prevent future incidents. Reduced pre-emptive repair benefits are not included in this analysis.

Interference Currents

From 2002 through 2013, operators reported 2 reportable incidents caused by interference current. This is an average of approximately 0.2 incidents per year that the proposed rule is targeted to address. PHMSA expects the proposed rule to effectively eliminate this pipeline failure cause, if properly implemented. Therefore, PHMSA assumed approximately 0.2 incidents per year would be averted.

Note that other external corrosion incidents may also have been caused by undetected interference currents, so that this estimate is conservative. In addition, proper cathodic protection will reduce the requirement for pipeline repairs necessary to prevent future incidents. Benefits from reduced pre-emptive repairs are not included in this analysis.

Internal Corrosion Controls

From 2010 through 2013, operators reported 60 reportable incidents caused by internal corrosion, 52 (87%) of which were attributed to known or suspected contaminants that PHMSA is addressing with the proposed rule. PHMSA expects the proposed rule to reduce but not completely eliminate failures caused by gas stream contaminants. Therefore, PHMSA assumed that the proposed rule would avert approximately three incidents per year.

In addition, reduced internal corrosion will yield additional benefits in the form of fewer repairs undertaken to prevent future incidents. Benefits from reduced pre-emptive repairs are not included in this analysis.

4.4.2 ESTIMATION OF BENEFITS

Table 4-12 shows the calculation of safety benefits from Topic Area 4. **Table 4-13** shows the results over the study period.

Table 4-12. Calculation of Safety Benefits, Topic Area 4 ((Millions, 2015$)		
Incidents Averted per Year[1]	**Average Cost per Incident[2]**	**Annual Benefits[3]**
7.2	$0.3	$2.4
1. Source: PHMSA best professional judgment (4.0 + 0.2 + 3.0) 2. See Table E-5. 3. Calculated as incidents averted × average cost per incident.		

Table 4-13. Present Value of Benefits, Topic Area 4 (Millions 2015$)			
7% Discount Rate		**3% Discount Rate**	
Total[1]	**Average Annual[2]**	**Total[1]**	**Average Annual[2]**
$23.3	$1.6	$29.4	$2.0
1. Present value over 15-year study period. 2. Total divided by 15.			

4.5 PIPELINE INSPECTION FOLLOWING EXTREME EVENTS

This section provides analysis of benefits of inspecting gas transmission pipelines following extreme events. The analytical approach is the same as for Topic Areas 3 and 4.

4.5.1 ANALYSIS ASSUMPTIONS

From 2003 through 2013, pipeline operators reported 85 reportable incidents in which storms or other severe natural force conditions damaged pipelines, resulting in failure. Operators reported total damages for these incidents of over $104M. Although the proposed rule would not guarantee that pipeline inspections and repair could be accomplished before all storm damaged pipe would fail, it would require that operators conduct inspections and repair in a prompt and timely manner, thus preventing some incidents. For illustration, PHMSA assumed that 0.5 incidents per year would be averted by implementation of the proposed regulation. The benefits would result from requiring operators to discover pipeline damage and make repairs sooner than they would in the absence of this rule.

4.5.2 ESTIMATION OF BENEFITS

Table 4-14 shows the calculation of safety benefits from Topic Area 5. **Table 4-15** shows the results over the study period.

Table 4-14. Calculation of Safety Benefits, Topic Area 5 (2015$)		
Incidents Averted per Year[1]	**Average Cost per Incident[2]**	**Annual Benefits[3]**
0.5	$114,077	$57,039
1. Source: PHMSA best professional judgment 2. See Table E-6. 3. Calculated as incidents averted × average cost per incident.		

Table 4-15. Present Value of Benefits, Topic Area 5 (Millions 2015$)			
7% Discount Rate		**3% Discount Rate**	
Total[1]	**Average Annual[2]**	**Total[1]**	**Average Annual[2]**
$555,869	$37,058	$701,352	$46,757

Table 4-15. Present Value of Benefits, Topic Area 5 (Millions 2015$)			
7% Discount Rate		3% Discount Rate	
Total[1]	Average Annual[2]	Total[1]	Average Annual[2]
1. Present value over 15-year study period. 2. Total divided by 15.			

4.6 TOPIC AREA 6: MAOP EXCEEDANCE REPORTS AND RECORDS VERIFICATION

PHMSA did not have information to estimate the benefits of this provision from the prestatutory baseline to accompany the estimate of such costs.

4.7 TOPIC AREA 7: LAUNCHER/RECEIVER PRESSURE RELIEF

This section addresses benefits from the launcher and receiver pressure relief provisions.

4.7.1 ANALYSIS ASSUMPTIONS

Because most modern launchers and receivers already have the safety equipment that is the target of the proposed rule, and because PHMSA has no data with which to establish an incident rate, PHMSA assumed, for illustration, that one launcher/receiver event would be averted over the course of the 15-year study period.

4.7.2 ESTIMATION OF BENEFITS

Table 4-16 shows the calculation of safety benefits from Topic Area 7. **Table 4-17** shows the results over the study period

Table 4-16. Calculation of Safety Benefits, Topic Area 7		
Total Incidents Averted[1]	VSL (millions)[2]	Total Benefits (millions)[3]
1	$9.4	$9.4
VSL = value of statistical life 1. Source: PHMSA best professional judgment 2. Approximately $9.4 million (2015$; per Department of Transportation internal guidance). 3. Over the 15-year study period. Calculated as incidents averted × VSL.		

Table 4-17. Present Value of Benefits, Topic Area 7 (Millions 2015$)			
7% Discount Rate		3% Discount Rate	
Total[1]	Average Annual[2]	Total[1]	Average Annual[2]
$6.1	$0.4	$7.7	$0.5
1. Present value over 15-year study period. 2. Total divided by 15.			

4.8 TOPIC AREAS 1-7: ENVIRONMENTAL BENEFITS

Natural gas pipeline incidents release greenhouse gases, primarily methane, into the atmosphere. These emissions contribute to climate change and social costs, as described in Section 3.9 and Appendix B. This section provides estimates of the social benefits from avoiding GHG emissions due to incidents described in Sections 4.1 through 4.7. A summary of estimated incidents averted is provided in **Table 4-18**.

Table 4-18. Summary of Estimated Incidents Averted, Topic Areas 1-7

Estimate	Topic Area							
	1	2	3	4	5	6	7	Total
Annual	5-15	n.e.	1	7	1	n.e.	0	14-24
Total[1]	74-221	n.e.	15	108	8	n.e.	1	205-353

Note: detail may not add to total due to independent rounding.
n.e. = not estimated
1. Calculated as annual estimate times 15 years.

PHMSA estimated the amount of natural gas, methane, and carbon dioxide releases that would be avoided each year based on the estimated number of incidents averted, historical average releases from incident reports, and assumptions regarding the composition of the gas. **Table 4-19** shows the data on gas released during incidents. In analyzing this data, PHMSA considered if the release ignited, as reported by the operator in the incident report (**Table 4-20**). If the release ignited, PHMSA applied an efficiency factor of 0.35 based on Stephens (2000)[44] and used 120 pounds of CO_2 produced per thousand cubic feet (MCF) of methane combusted to estimate the amount of CO_2 released from combusted methane (EPA, 1995).[45] **Table 4-21** shows these results.

Table 4-19. Gas Released During Gas Transmission Pipeline Incidents (2010 – 2014)

Year	Incidents	Natural Gas Released (MCF)	Average per Incident (MCF)
2010	105	2,351,022	22,391
2011	114	2,718,692	23,848
2012	102	2,105,292	20,640
2013	103	1,688,265	16,391
2014	129	2,467,085	19,125
Total	**553**	**11,330,355**	**20,489**

Source: Gas Transmission Incident Reports
MCF = thousand cubic feet

Table 4-20. Ignition or Explosion of Gas Released During Gas Transmission Pipeline Incidents (2010 – 2014)

Year	Ignition or Explosion	No Ignition or Explosion
2010	19	86
2011	13	101
2012	15	87
2013	11	92
2014	16	113
Total (%)	74 (13%)	479 (87%)

Source: Gas Transmission Incident Reports

[44] Stephens, M.J., *A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines*, Topical Report prepared for the Gas Research Institute. GRI-00/0189, October 2000.
[45] Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, AP-42, Fifth Edition, January 1995.

Table 4-21. Greenhouse Gas Emissions per MCF of Natural Gas Released		
Gas	**Methane (MCF)**	**Carbon Dioxide(lbs)**
No ignition or explosion[1]	0.96	1.5
Ignition[2]	0.62	41.7

lbs = pounds
MCF = thousand cubic feet
CH_4 = methane
CO_2 = carbon dioxide
1. MCF CH_4 = 1 MCF gas × 96% methane; lbs CO_2 = 1 MCF gas × 1.3% $C0_2$ × 114.4 lbs/MCF.
2. MCF CH_4 = 1 MCF gas × 96% methane ×1-0.35 combustion efficiency factor); lbs CO_2 = (1 MCF gas × 1.3% $C0_2$ × 114.4 lbs/MCF) + (1 MCH methane × 96% methane × 0.35 combustion efficiency factor).

Table 4-22 shows the estimated reduction in annual emissions.

Table 4-22. Greenhouse Gas Emission Reductions Per Year				
Scenario[1]	**Natural Gas Combusted (MCF)[2]**	**Natural Gas Not Combusted (MCF)[3]**	**CH_4 Emissions Reduction (MCF)[4]**	**$C0_2$ Emissions Reduction (lbs)[5]**
Low	37,556	243,098	256,006	1,926,905
High	64,487	417,423	439,588	3,308,688

MCF = thousand cubic feet
CH_4 = methane
CO_2 = carbon dioxide
1. Low scenario reflects low assumption of defect failures and avoided incidents; high scenario reflects high assumption of defect failures and avoided incidents.
2. Gas released × 13%
3. Gas released × 87%
4. (Combusted × 0.62) + (not combusted × 0.96); see tables 4-19 and 4-20.
5. (Combusted gas × 116 lbs. $C0_2$/MCF gas) + (not combusted gas × 1.5 lbs. $C0_2$).

To value the avoided emissions, PHMSA used the U.S. Social Cost of Carbon (SCC) Interagency Working Group's current estimates of SCC and estimates of SCM that were developed by Marten et al., (2014), as appropriate. The sum of these values is the total social benefits due to avoided greenhouse gas emissions (**Table 4-23**). See Appendix B for detailed calculations of these values.

Table 4-23. Summary of Total Climate Benefits, Topic Areas 1-7 (Millions 2015$)[1]		
Pollutant	**Avoided Emissions**	**Social Cost (3%)**
Methane (MCF)	3,840,090-6,593,818	$113.0-$194.0
Carbon dioxide (MT)	13,110-22,512	$0.6-$1.0
Total	**NA**	**$113.5-$195.0**

MCH = thousand cubic feet
MT = metric tons
1. Total over 15-year period calculated as emissions from Table 4-22 multiplied by 15 years and valued using the estimates in Appendix B.

In addition, pipeline incidents leading to the combustion of natural gas will also generate emissions of urban air pollutants, including carbon monoxide, nitrogen oxides, and hydrocarbons. Uncontrolled burning from a pipeline incident is likely to be very inefficient compared with fuel burned in an engine or boiler, hence urban air pollutant emissions are likely to be relatively high in comparison with the amount of fuel combusted. "Rich" gas from gathering line incidents will generate more pollutants (particularly heavier hydrocarbons) than pipeline quality natural gas. Pipeline incidents that cause combustion of surrounding vegetation or structures will cause disproportionate emissions of urban air pollutants, and some hazardous air pollutants. PHMSA lacks a basis for making an estimate of the quantity of these emissions, and the social value may be location dependent.

4.9 SUMMARY OF BENEFITS

Table 4-24 provides a summary of safety benefits by topic area. Table 4-25 summarizes the total benefits climate change benefits of the proposed rule due to incidents, and therefore emissions, avoided.

Table 4-24. Present Value of Safety Benefits, Topic Areas 1-7 (Millions 2015$)

Topic Area	7% Discount Rate		3% Discount Rate	
	Total[1]	Annual[2]	Total[1]	Annual[2]
1	$245.5 -$667	$16.4 -$44.5	$309.7 -$841.5	$20.6 -$56.1
2	n.e.	n.e.	n.e.	n.e.
3	$8.2	$0.5	$10.3	$0.7
4	$23.3	$1.6	$29.4	$2.0
5	$0.6	$0.0	$0.7	$0.0
6	n.e.	n.e.	n.e.	n.e.
7	$6.1	$0.4	$7.7	$0.5
Total	**$283.5 -$705.0**	**$18.9 -$47.0**	**$357.8 -$889.6**	**$23.9 -$59.3**

n.e. = not estimated
1. Present value over 15-year study period.
2. Total divided by 15.

Table 4-25. Climate Change Benefits, Topic Areas 1-7 (Millions 2015$)

	Total[1]	Annual[2]
1	$40.9 -$122.3	$2.7 -$8.2
2	n.e.	n.e.
3	$8.3	$0.6
4	$59.7	$4.0
5	$4.1	$0.3
6	n.e.	n.e.
7	$0.6	$0.0
Total	**$113.5 -$195.0**	**$7.6 -$13.0**

n.e. = not estimated
1. Total value over 15-year study period.
2. Total divided by 15.

Table 4-26 synthesizes these results, including the cost savings benefits described in **Table 4-8**, to calculate the total benefits of Topic Areas 1-7.

Table 4-26. Present Value of Total Benefits, Topic Areas 1-7 (Millions 2015$)[1]				
Benefits Category	**7% Discount Rate**		**3% Discount Rate**	
	Total	**Average Annual**	**Total**	**Average Annual**
Safety	$283.5 -$705	$18.9 -$47.0	$357.8 -$889.6	$23.9-$59.3
Cost savings	$2,667.6	$177.8	$3,3655.7	$224.4
Climate change	$113.5 -$195.0	$7.6 -$13.0	$113.5 -$195.0	$7.6 -$13.0
Total	**$3,064.7 -$3,567.6**	**$204.3 -$237.8**	**$3,837.0 -$4,450.3**	**$255.8 -$296.7**
1. Total is present value over 15-year study period; average annual is total divided by 15.				

5. COMPARISON OF BENEFITS AND COSTS FOR TOPIC AREAS 1 THROUGH 7

This section provides a comparison of benefits and costs for Topic Areas 1 through 7 which apply to onshore gas transmission pipelines. This section also addresses alternatives to the proposed rule in these topic areas.

5.1 BENEFITS AND COSTS OF PROPOSED RULE

Sections 3.1 through 3.7 describe the cost estimates for each of the seven topic areas. Sections 4.1 through 4.8 describe the benefit estimates associated with these topic areas. Both the costs and benefits are dominated by Topic Area 1 which would require integrity assessments for approximately 16,000 miles of pipelines. The regulatory impact of other topic areas is relatively minor in comparison. The proposed rule, as described under Topic Area 1, would require that an initial integrity assessment be completed within 15 years of the effective date of the proposed rule. Therefore, 15 years is the timeframe for this analysis to analyze the entire initial assessment period. However, PHMSA expects the regulation to have long-term impact with benefits occurring long beyond the 15-year study period.

Tables 5-1 through **Table 5-6** provide a summary of the present value benefits and costs. For comparison, the total estimated social cost ($534 million at a 7% discount rate) is approximately one-third the consequence of the San Bruno incident (see Appendix D).

Table 5-1. Summary of Average Annual Present Value Costs, Topic Areas 1-7, 7% Discount Rate (Millions 2015$)

Topic Area	Compliance	Social Cost of Methane[1]	Total
1	$16.0	$1.8	$17.8
2	$2.2	$0.0	$2.2
3	$0.7	$0.0	$0.7
4	$6.3	$0.0	$6.3
5	$0.1	$0.0	$0.1
6	$0.2	$0.0	$0.2
7	$0.0	$0.0	$0.0
Total	**$25.4**	**$1.8**	**$27.3**

1. Using 3% discounted values (see Appendix B).

Table 5-2. Summary of Average Annual Present Value Costs, Topic Areas 1-7, 3% Discount Rate (Millions 2015$)

Topic Area	Compliance	Social Cost of Methane	Total
1	$20.2	$1.8	$22.0
2	$1.3	$0.0	$1.3
3	$0.8	$0.0	$0.8
4	$7.9	$0.0	$7.9
5	$0.1	$0.0	$0.1
6	$0.2	$0.0	$0.2
7	$0.0	$0.0	$0.0

Table 5-2. Summary of Average Annual Present Value Costs, Topic Areas 1-7, 3% Discount Rate (Millions 2015$)			
Topic Area	**Compliance**	**Social Cost of Methane**	**Total**
Total	**$30.5**	**$1.8**	**$32.3**

Table 5-3. Summary of Average Annual Present Value Benefits, Topic Areas 1-7, 7% Discount Rate				
Topic Area	**Safety**	**Cost Savings[1]**	**Climate[2]**	**Total**
1	$16.4 -$44.5[3]	$177.8	$2.7 -$8.2[3]	$196.9 -$230.5
2	n.e.	n.e.	n.e.	n.e.
3	$0.5	$0.0	$0.6	$1.1
4	$1.6	$0.0	$4.0	$5.5
5	$0.0	$0.0	$0.3	$0.3
6	n.e.	n.e.	n.e.	n.e.
7	$0.4	$0.0	$0.0	$0.4
Total	**$18.9 -$47.0**	**$177.8**	**$7.6 -$13**	**$204.3 -$237.8**

n.e. = not estimated
1. Material verification cost savings would provide comparable safety with a pressure test at or above 1.25 times maximum allowable operating pressure and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods.
2. Using 3% discounted values. TA 1 includes range for uncertainty.
3. Range reflects uncertainty in incidents averted rates, see Table 4-2 and Table 4-3.

Table 5-4. Summary of Average Annual Present Value Benefits, Topic Areas 1-7, 3% Discount Rate (Millions 2015$)				
Topic Area	**Safety**	**Cost Savings[1]**	**Climate[2]**	**Total**
1	$20.6 -$56.1[3]	$224.4	$2.7 -$8.2[3]	$247.8 -$288.6
2	n.e.	n.e.	n.e.	n.e.
3	$0.7	$0.0	$0.6	$1.2
4	$2.0	$0.0	$4.0	$5.9
5	$0.0	$0.0	$0.3	$0.3
6	n.e.	n.e.	n.e.	n.e.
7	$0.5	$0.0	$0.0	$0.6
Total	**$23.9 -$59.3**	**$224.4**	**$7.6 -$13.0**	**$255.8 -$296.7**

n.e. = not estimated
1. Material verification cost savings would provide comparable safety with a pressure test at or above 1.25 times maximum allowable operating pressure and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods.
2. Using 3% discounted values. TA 1 includes range for uncertainty in incidents averted rates (see Table 4-2 and Table 4-3).
3. Range reflects uncertainty in incidents averted rates, see Table 4-2 and Table 4-3.

Table 5-5. Summary of Average Annual Present Value Benefits and Costs, Topic Areas 1-7, 7% Discount Rate (Millions 2015$)

Topic Area	Average Annual Benefits	Average Annual Costs	Benefit: Cost Ratio
1	$196.9 -$230.5[1]	$17.8	11.1-12.9
2	n.e.[2]	$2.2	n.e.
3	$1.1	$0.7	1.7
4	$5.5	$6.3	0.9
5	$0.3	$0.1	4.3
6	n.e.	$0.2	n.e.
7	$0.4	$0.0	18.5
Total	**$204.3 -$237.8**	**$27.3**	**7.5-8.8**

n.e. = not estimated
1. Reflects uncertainty in incident averted rates. See Tables 4-2 and 4-3.
2. Break even value of benefits would equate to approximately one incident averted over the 15-year study period.

Table 5-6. Summary of Average Annual Present Value Benefits and Costs, Topic Areas 1-7, 3% Discount Rate (Millions $2015)

Topic Area	Average Annual Benefits	Average Annual Costs	Benefit: Cost Ratio
1	$247.8 -$288.6[1]	$22.0	11.3 -13.1
2	n.e.[2]	$1.3	n.e.[2]
3	$1.2	$0.8	1.5
4	$5.9	$7.9	0.8
5	$0.3	$0.1	4.5
6	n.e.	$0.2	n.e.
7	$0.6	$0.0	23.0
Total	**$255.8 -$296.7**	**$32.3**	**7.9 -9.2**

n.e. = not estimated
1. Reflects uncertainty in incident averted rates. See Tables 4-2 and 4-3.
2. Break even value of benefits would equate to less than one incident averted over the 15-year study period.

5.2 LIMITATIONS AND UNCERTAINTIES

There is substantial uncertainty in several parameters underlying the analysis including affected mileage, unit costs, effectiveness, and value of avoiding incidents. With respect to the affected mileage, commitments to expand assessment and repair programs beyond HCAs have already been made by the industry in PHMSA's workshops and in response to the ANPRM dated August 25, 2011 (76 FR 53086).[46] These commitments have the effect of reducing the compliance costs and the benefits associated with the proposed rule.

Also, in estimating costs and avoided risks of incidents, PHMSA relied on existing experience which reflects primarily assessment in HCAs. Extrapolation of this experience

[46] Letter from Terry D. Boss, Senior Vice President of Environment, Safety and Operations, Interstate Natural Gas Association of America (INGAA) to Mike Israni, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, dated January 20, 2012, "*Safety of Gas Transmission Pipelines*, Docket No. PHMSA-2011-0023"

could overstate costs in MCAs due to the lower density of development. There is also uncertainty regarding the effectiveness of the proposal in Topic Area 1 to reduce the risks of incidents. For example, NTSB (2015)[47] identified areas of integrity management where improvements can be made to further enhance the safety of gas transmission pipelines in HCAs. PHMSA sponsored research on the effectiveness of IM and IVP based on real-world experience shows that certain anomalies found in legacy pipe are not detected using IM.[48] However, the study does not provide a basis to estimate the number of defects that would be discovered by the proposed rule. The accuracy of PHMSA's estimates of incidents averted is largely dependent on the accuracy of the defect discovery rates shown in Table 4-1, and the estimated percentages of defects that, absent TA1's requirements, would result in incidents as shown in Table 4-2 (which are presented as ranges). In addition, there is no data on the extent of mileage that would meet the definition of an MCA.

Costs could also increase or decrease over time due to a variety of factors including technological improvement, changes in industry structure, and changes in prices. In particular, PHMSA expects ongoing development of new inline integrity assessment technologies to reduce the cost of ILI and to allow line segments that are currently unpiggable using conventional technology to use ILI without significant upgrade or replacement of the segment. A reduction in these assessment costs over time would further increase the net benefit of the proposed rule.

The benefits of reducing risks represent consequences from incidents reported by pipeline operators which do not include all consequences associated with incidents. Operators submit their casualty and direct loss/damage estimates only which may undervalue the impact of all consequences since other consequential costs, including indirect costs, to operators, other stakeholders, or society are not included. The inclusion of these unreported consequential costs of incidents would increase the estimated safety benefits associated with the proposed rule. The averages of reported consequences from past incidents could under- or overstate future consequences.

5.3 BENEFITS AND COSTS OF ALTERNATIVES

This section addresses alternatives to the proposed rule in Topic Areas 1 through 7.

Regulatory analyses typically consider the alternative of taking no action, maintaining the status quo. As a result, no new requirements would be levied. PHMSA considered the no action alternative for all Topic Areas. Sections 1-4 provide detailed discussion of the need for the proposed rule and benefits to be gained that justify a regulatory alternative. The sections below also note any particular considerations in this regard.

5.3.1 ALTERNATIVES FOR TOPIC AREA 1

This section discusses alternatives PHMSA considered to the proposed requirements in Topic Area 1.

[47] National Transportation Safety Board (NTSB). 2015. Integrity Management of Gas Transmission Pipelines in High Consequence Areas. Safety Study NTSB/SS-15/01 PB2015-102735. Online at http://www.ntsb.gov/safety/safety-studies/Documents/SS1501.pdf.

[48] J.F. Kiefner and K. M. Kolovich. 2012. ERW and Flash Weld Seam Failures. Final Report to Batelle, U.S. Department of Transportation Agreement No. DTPH56-11-T-000003. September 24.

5.3.1.1 ALTERNATIVE 1: MORE STRINGENT MCA CRITERIA AND EXPANSION OF TESTING TO RE-ESTABLISH MAOP FOR ADDITIONAL PIPE

Alternative 1 provides:

- More stringent criteria for defining an MCA (reduces number of buildings and persons in the PIR from five to one)
- Integrity assessments of nonpiggable mileage in Class 1 and 2 locations
- Testing to re-establish MAOP for pipe susceptible to material or construction defects that were pressure tested to less than 1.25 times MAOP, and additional mileage in MCAs in Classes 1 and 2 that have not been pressure tested.

These additional criteria would more comprehensively address NTSB recommendations P-11-14 and P-11-15 (compared to the proposed rule).

PHMSA performed a quantitative estimate of the costs and benefits for this alternative. PHMSA used the same analysis approach and assumptions as described in Section 3.1 (costs) and 4.1 (benefits), with adjustments to account for changes in that the scope of the rule. PHMSA made the same assumptions for assessment of unpiggable Class 1 and 2 pipe as for other segments in the base analysis that are not piggable (i.e., used the same percentage of pressure test and direct assessment as for Class 3 and 4 locations). For benefits, PHMSA used the average consequences of incidents from 2003-2013 preventable by integrity management that occurred outside of HCAs excluding those that did not result in property damage, death, or injury (see Table E-9). The average incident severity for incidents prevented by integrity assessments and establishing MAOP may be lower if more stringent MCA criteria is applied because more stringent criteria would include pipeline that is in areas with fewer people and property. **Table 5-7** and **Table 5-8** show the resulting costs and benefits.

Table 5-7. Present Value Incremental Compliance Costs, Topic Area 1: Alternative 1 (Millions 2015$)[1]

Topic Area	Miles	Annual (7%)	Total (7%)	Annual (3%)	Total (3%)
Re-establish MAOP: HCA > 30% SMYS	909	$0.4	$5.8	$0.5	$7.4
Re-establish MAOP: Inadequate Records	4,363	$6.9	$103.0	$8.7	$130.0
Integrity Assessment: MCA[2]	18,294	$24.9	$373.5	$31.4	$471.2
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; MCA Class 1 and 2[3]	8,607	$5.0	$74.4	$6.3	$93.9
Total	**32,173**	**$37.1**	**$556.7**	**$46.8**	**$702.4**

1. Total over 15 years; annual is total divided by 15.
2. Represents change from proposed rule (1 building MCA criteria; nonpiggable Class 1 and 2 miles must be assessed).
3. Represents change from proposed rule (1 building MCA criteria; MCA Class 1 & 2 miles must be assessed).

Table 5-8. Present Value Safety Benefits,[1] Topic Area 1: Alternative 1 (Millions 2015$)[2]						
Topic Area	**Annual Incidents Averted**	**Annual (7%)**	**Total (7%)**	**Annual (3%)**	**Total (3%)**
Re-establish MAOP: HCA > 30% SMYS	0.2-0.6	$3.5-$8.6	$52.1-$128.4	$4.4-$10.8	$65.8-$162
Re-establish MAOP: Inadequate Records	1.4-3.8	$9.4-$24.7	$140.8-$371.1	$11.8-$31.2	$177.7-$468.2
Integrity Assessment: MCA	6.1-18.9	$2.9-$13.3	$44.2-$200.1	$3.7-$16.8	$55.8-$252.5
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; MCA Class 1 and 2	2.6-8.7	$2.5-$10.1	$36.8-$151.2	$3.1-$12.7	$46.5-$190.8
Total	**10.4-32.0**	**$18.3-$56.7**	**$274.0-$850.9**	**$23.0-$71.6**	**$345.7-$1,073.6**

1. Does not include cost savings or environmental benefit
2.Total over 15 years; annual is total divided by 15. Based on average consequences per MCA incident of $0.7 million (see Table E-9).

PHMSA estimated that this alternative would provide approximately 31,000 miles of additional pipe that contained residences or occupied sites inside the PIR with the additional protections afforded other segments covered by the proposed rule.

In addition, a major constituency of the pipeline industry (INGAA) has committed to apply IM principles to all segments where any persons are located. This is comparable to PHMSA's MCA definition contemplated in this alternative, thus showing industry support for the policy objective of applying additional protections for any segments with a house/site inside the PIR.

5.3.1.2 TOPIC AREA 1 - ALTERNATIVE 2: MORE LIMITED SCOPE OF MCAS BY EXCLUDING PIPELINES LESS THAN 8-INCHES DIAMETER

PHMSA considered restricting the application of MCA requirements to pipe segments that are ≥8" in diameter. Exempting MCA pipe <8" in non-HCA Class 1 or non-HCA Class 2 would result in minimal mileage reduction to the scope of the rule, because:

- Less 15% of onshore natural gas transmission line mileage is smaller than 8" in diameter.
- The PIR for small diameter is very small.
- The statutory mandate to verify MAOP for any pipe in HCA, Class 3, and Class 4 locations for which records are insufficient to confirm the established MAOP would still apply to these smaller pipe sizes. Thus, pipe segments <8" in diameter that meet the Act's criteria would still require an integrity assessment, however they would not require additional assessments under the Act.

To illustrate, the area of an impact circle is calculated as $A = (0.69\pi)^2 \times P \times D^2$ where P = operating pressure and D = the diameter[49]. All else equal, a 4" diameter pipe segment impacts a quarter less area than an 8" diameter pipe segment. PHMSA estimated that the pipeline mileage which would require an integrity assessment would be reduced by only

[49] Area = πr^2 where the radius is the PIR equation in 49 CFR §192.903.

about 4%. With this alternative, some residences would remain unprotected even though they were within the PIR.

5.3.1.3 TOPIC AREA 1 - ALTERNATIVE 3: EXPAND SCOPE OF HCA INSTEAD OF CREATING MCA

PHMSA considered expanding the scope of HCAs instead of creating MCAs. PHMSA received a number of comments on this approach in response to the 2011 ANPRM. This approach would be counter to a graded approach based on risk (i.e., risk based gradation of requirements to apply progressively more protection for progressively greater consequence locations). By simply expanding HCAs, PHMSA would be simply lowering the threshold for what is considered “high consequence.”

Expanding HCAs would require that all IM program elements be applied to pipe located in a newly designated HCA. The proposed rule would only apply three IM program elements (assessment, periodic reassessment, and remediation of discovered defects) to the category of pipe that has lesser consequences than HCAs (i.e., MCAs), but not to segments without any structure or site within the PIR (arguably “low consequence areas”). **Table 5-9** summarizes this risk-based, graded approach to application of IM requirements.

Table 5-9. Risk-based Gradation for Application of IM Program Elements

Category	Program Elements Applied
High Consequence Areas	All, including risk analysis preventive/mitigative measures, assessment, periodic reassessment, and remediation of discovered defects five year reassessment interval, rapid repair of discovered anomalies, plus non-IM prescriptive safety standards
Moderate Consequence Areas	Assessment, periodic reassessment, and remediation of discovered defects, plus non-IM prescriptive safety standards
Segments with no buildings intended for human occupancy or identified site or occupied site or major highway ROW within the PIR	Non-IM prescriptive safety standards only

Long term reassessment costs would approximately triple based on an almost three to one ratio of reassessment interval. Also, there would be additional costs to apply other program elements (most notably the risk analysis and preventive/mitigative measures program elements) to additional segments.

5.3.1.4 TOPIC AREA 1 - ALTERNATIVE 4: APPLY THE PROPOSED REQUIREMENTS TO ALL NON-HCA PIPE SEGMENTS

PHMSA considered expanding the proposed requirements such that they would apply to all non-HCA gas transmission pipelines. However, this option would dilute the impact of operator’s maintenance budgets by requiring assessments on segments deemed to be in “low consequence” locations (i.e., segments in locations without any structure intended for human occupancy or occupied site inside the PIR). PHMSA estimated that approximately 59,000 miles of onshore gas transmission pipeline would meet the definition of MCA (proposed) or HCA. The remaining 243,000 miles of gas transmission pipeline would not be in a location that would contain any structures intended for human occupancy, or identified site, or occupied site, or major highway right-of-way. Although it is possible that someone could still be injured at such locations (e.g., persons in transient nearby at the time of a failure, workers performing maintenance on the pipeline, other parties performing excavation activities near the pipeline, etc.), PHMSA expects that the increase in benefit would be incremental, and not proportional to the cost.

5.3.1.5 TOPIC AREA 1 - ALTERNATIVE 5: ACCELERATE THE COMPLIANCE DEADLINE AND SHORTEN THE REASSESSMENT INTERVAL

PHMSA considered shorter a compliance deadline (ten years) and a shorter reassessment interval (15 years) for MCA assessments. The assessment timeframes in the proposed rule apply relaxed timeframes to MCAs, compared to HCAs.

The industry was originally required to perform baseline assessments for approximately 20,000 miles of HCA pipe within approximately eight years. PHMSA estimated that approximately 41,000 miles of pipe would require an assessment within 15 years under this proposed rule, thus constituting a comparable level of effort on the part of industry.

The maximum HCA reassessment interval is 20 years for low stress pipe.[50] The 20 year interval aligns with the longest interval allowed for any HCA pipe, which is 20 years for pipe operating less than 30% SMYS.[51] A reassessment interval of 15 years for MCAs would be shorter than the reassessment interval for some HCAs.

PHMSA also considered that compliance with the proposed rule would be performed in parallel with ongoing HCA reassessments at the same time, thus resulting in greater demand for ILI tools and industry resources than during the original IM baseline assessment period. In addition, the proposed rule incorporates other assessment goals, including IVP, MAOP verification, and material documentation, thus constituting a larger/more costly assessment effort than originally required under IM rules. For the above reasons, the proposed rule would require full utilization or expansion of industry resources devoted to assessments. Therefore, compressing the timeframes could be infeasible. PHMSA also considered the possibility that demands on the industry’s assessment capability might drive assessment costs higher.

5.3.1.6 TOPIC AREA 1 – ALTERNATIVE 6: PERFORM PRESSURE TESTING TO VERIFY MAOP FOR HCAS AND CLASS 3 AND CLASS 4 LOCATIONS

Section 23 of the Act specifies that PHMSA require operators to (1) re-confirm MAOP for pipelines in HCAs and Class 3 and Class 4 locations if records are not available and (2) issue regulations requiring that operators test previously untested pipeline segments in HCAs. Both of these activities would conventionally require a pressure test in accordance with subpart J of Part 192. This approach would mimic the regulations issued by CPUC in the aftermath of the San Bruno incident, in response to the NTSB recommendations that are related to the mandates in Section 23 of the Act.

PHMSA performed a screening benefit-cost evaluation for such pressure testing, limited to HCAs and Class 3 and Class 4 locations. The screening evaluation used the following inputs from the detailed analysis described in sections 3 and 4.

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[50] See 49 CFR 192.939(b)(6)

[51] Note, however, that Confirmatory Direct Assessment (CDA) would not be required for MCAs at seven year intervals, as is required for HCAs.

- Segment mileage within the scope of this alternative from the estimates for IVP mileage in Table 3.1-4. PHMSA used the subset of proposed IVP mileage estimated for HCAs (3,158), Class 3 non-HCAs (2,514), and Class 4 non-HCAs (2) for a total of 5,674miles.
- PHMSA applied the same unit costs for pressure tests as for Section 3.1 of the analysis. The mean costs for the small, medium, and large diameter subsets were averaged to approximate a weighted average unit cost as described in Table 3-15. For this screening analysis PHMSA used the midpoint between the intrastate and interstate values ($215,248 per mile).
- The benefit estimated from incidents averted from pressure test failures is based on applying the pressure test defect detection and failure rates shown in Appendix C (Table C-2) using the process described in section 4.1.2.2.2. The results were scaled in proportion to the mileage estimate for this alternative (5,674).
- To calculate benefits, PHMSA multiplied the estimated incidents averted for HCA mileage by the average HCA incident consequence of $23 million (Appendix E; Table E-3) and the Non-HCA incidents averted by the class 3 and class 4 non-HCA average incident consequence of $0.1M (Appendix E; Table E-8)

The results of this screening evaluation are an estimated total cost for this alternative of $1.22 billion and total benefit of $856 million (nominal values).

5.3.1.7 TOPIC AREA 1 – ALTERNATIVE 6: NO ACTION

As discussed above, commitments to expand assessment and repair programs beyond HCAs have already been made by INGAA[52] in PHMSA's workshops and in response to the ANPRM dated August 25, 2011 (76 FR 53086). These commitments have the effect of reducing the compliance costs and the benefits associated with the proposed rule, and would improve safety under the no action alternative.

5.3.2 ALTERNATIVE FOR TOPIC AREA 2: NO ACTION

With respect to the no action alternative for Topic Area 2 requirements, the Act requires PHMSA to issue regulations on some of the topics addressed in the proposed rule, including seismic risk (Section 29 of the Act), and a technical correction regarding extension of reassessment intervals [Section 5(e) of the Act].

5.3.3 TOPIC AREA 3 ALTERNATIVE 2: EXTEND COMPLIANCE DEADLINES

One option to reduce the cost of the proposed rule is to extend the new compliance deadlines for development and implementation of MoC processes that apply to all gas transmission pipelines.

Extending the regulatory compliance deadlines would not reduce costs, though it would potentially defer costs by spreading them over a longer time period. Deferral would only

[52] Letter from Terry D. Boss, Senior Vice President of Environment, Safety and Operations, Interstate Natural Gas Association of America (INGAA) to Mike Israni, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, dated January 20, 2012, "*Safety of Gas Transmission Pipelines*, Docket No. PHMSA-2011-0023"

reduce costs if there are logistical bottlenecks to faster implementation. PHMSA is not aware of any logistical bottlenecks within the proposed timeframe that would raise implementation costs within the scope of the proposed compliance deadline. Although PHMSA did not explicitly analyze this alternative, generally, deferring a project with positive discounted net benefits will reduce net benefits.

Further, extending the compliance deadlines would potentially defer achieving the intended goal of formally controlling changes to pipeline systems and facilities during the period when the compliance deadline would be delayed. While pipeline incidents are not typically attributed to change management as a primary cause, it is a critical element in ensuring that pipeline operators evaluate the safety and operating parameters of their systems based upon up-to-date and accurate information about their systems. Effective Management of Change is an important complement to the assessments required by the Integrity Management Program generally and this proposes rule, because operators will be making changes to their pipelines as they repair anomalies detected by the required assessments. Failing to put change management procedures in place ahead of the expanded inspection regime risks injecting potentially hazardous inaccuracies into operator data as their systems evolve. An undocumented field change (usage of non-pipe grade pup pieces) was a major contributing factor of the San Bruno incident, according to NTSB.

Thus, this alternative is not considered for further development in this analysis.

5.3.4 ALTERNATIVES FOR TOPIC AREA 4

PHMSA considered a number of technical alternatives for enhanced corrosion control during development of the proposed rule. Examples include:

- Holiday testing ("jeeping") in the trench with the pipe being supported and then moving the supports to check under them.
- Premium quality backfill such as clean washed sand bedding
- Second layer of coating to protect the corrosion protection coating from damage
- Additional gas stream processing/cleaning

The above alternatives would be more expensive to implement, without any expected appreciable benefit, and therefore were not considered further in this analysis.

5.3.5 ALTERNATIVE FOR TOPIC AREA 5: EXTEND COMPLIANCE DEADLINES

PHMSA considered extending the compliance deadlines for development or revision of procedures to specify that operators are to conduct surveillances following extreme weather or natural disaster, or similar events. Delaying compliance deadlines would not reduce total costs, though some costs would be deferred and spread out over a longer time period. Deferral would only reduce costs if there are logistical bottlenecks to faster implementation. PHMSA is not aware of any logistical bottlenecks that would raise implementation costs within the scope of the proposed compliance deadline. Although PHMSA did not explicitly analyze this alternative, generally, deferring a project with positive discounted net benefits will reduce net benefits.

Delaying compliance with deadlines would potentially have the same adverse consequences as taking no regulatory action for the time period before compliance would be required. Each year, hurricanes, floods, mudslides, tornadoes, and other extreme events place pipelines at a greater risk of failure. From 2003 through 2013, pipeline operators reported 85 reportable incidents in which storms or other severe natural force conditions damaged pipelines, resulting in failure. Inspections triggered by the proposed rule should lead to the detection and repair of some event-induced damage, thus reducing the frequency of both immediate and some future incidents.

Because this is a relatively low cost proposal, and cost savings would be minimal compared to the potential benefit of prompt implementation, this alternative was not considered for further development in this analysis.

5.3.6 ALTERNATIVE FOR TOPIC AREA 7

This section discusses alternatives for Topic Area 7.

5.3.6.1 ALTERNATIVE 1: NO ACTION

Not taking action would continue the exposure of a small number of pipeline workers to routine safety hazards due to potentially high pressures within launchers and receivers. Hazards due to the high pressures could potentially result in serious injury or death. Thus, PHMSA did not consider this alternative further.

5.3.6.2 ALTERNATIVE 2: EXTEND COMPLIANCE DEADLINES

PHMSA considered extending the compliance deadlines associated with the development of design and testing specifications and the design, installation and testing of the launcher and receiver safety devices. This alternative would not reduce total costs, though it would defer costs and spread them over a longer time period. Deferral would only reduce costs if there are logistical bottlenecks to faster implementation. PHMSA is not aware of any logistical bottlenecks that would raise implementation costs within the scope of the proposed compliance deadline. Although PHMSA did not explicitly analyze this alternative, generally, deferring a project with positive discounted net benefits will reduce net benefits.

Because of the large increase in-line inspection assessment required by the proposed rule, delaying the compliance deadline would expose persons to avoidable risks. Delaying action would continue exposure of a small number of pipeline workers to routine safety hazards due to potentially high pressures within launchers and receivers. Hazards due to the high pressures could potentially result in serious injury or death. Thus, PHMSA did not consider this alternative for further development in this analysis.

6. BENEFIT PERTAINING TO TOPIC AREA 8 (GAS GATHERING LINES)

PHMSA currently regulates only an estimated 3% of the total onshore gas gathering infrastructure mileage. It is essential to begin collecting incident and infrastructure data on all of the currently unregulated mileage, to better identify, characterize, and assess its risk and inform future rulemaking. The proposed rule would apply new safety provisions to approximately 69,000 miles of the currently unregulated onshore gas gathering lines. Additionally, the proposed rule would mandate reporting for all of the approximately 356,000 miles of currently unregulated lines. Note that offshore gathering lines are currently subject to both the reporting and safety provisions of PHMSA's regulations.

6.1 DESCRIPTION OF THE TARGETED THREATS

Excavation damage remains a leading cause of onshore pipeline incidents. The approximately 69,000 miles of higher-stress and larger-diameter gas gathering lines that would be newly regulated under the proposed rule would be subjected to select safety provisions of PHMSA's requirements intended to prevent excavation damage.

PHMSA incident data reported over the past 20 years shows that nearly half (49%) of incidents are caused by corrosion. The majority (86%) of those are caused by internal corrosion. High moisture content, which can lead to internal corrosion, is typical for unprocessed or partially processed gas that many gathering lines transport. Corrosion failures are sensitive to operating stresses; pipelines at higher operating pressures and higher stress levels are more likely to rupture (instead of slowly leak) when the pipe wall is thinned due to corrosion. Under the proposed rule, the 68,749 miles of higher-stress and larger-diameter gathering lines would also be subjected to the safety provisions of PHMSA's requirements intended to prevent internal and external corrosion.

6.2 IDENTIFICATION OF THE SAFETY PERFORMANCE BASELINE

PHMSA expects that safety benefits would be achieved by reducing the potential for corrosion and excavation damage incidents that could affect the 69,000 miles of the higher-stress, larger-diameter onshore gathering lines by regulating them under the proposed rule. The safety performance baseline for this proposed rule is the performance of these gas gathering lines in their unregulated state. Because these lines are currently unregulated by PHMSA, PHMSA has no data upon which to establish this baseline performance directly, and, instead, has utilized incident data that is available on comparable regulated lines.

PHMSA established the range of actual incident rates on regulated gas gathering lines in the years prior to PHMSA's 2006 rulemaking referenced earlier in this RIA. (This 2006 rule selectively applied corrosion, excavation damage, and other safety measures comparable to those proposed in this rule to a new category of similar gas gathering lines, so safety performance after this time period would be less representative of an unregulated state.) Assuming that the current performance of unregulated gas gathering lines is generally less safe than for regulated gas gathering lines, PHMSA established a typical high value for incident rates for the time period prior to 2006, with this value approximating the baseline safety performance of unregulated gas gathering lines.

As a result, and for the purposes of this analysis, PHMSA assumed a baseline incident rate for corrosion and excavation damage incidents of 0.329 incidents per 1,000 miles per year. This value represents the average corrosion and excavation damage incident rate on unregulated, onshore gathering lines for five years prior to the implementation of corrosion control and damage prevention requirements (**Table 6-1**). This 0.329 average incident rate equates to a baseline of 22.6 corrosion and excavation damage incidents per year on these currently unregulated onshore gas gathering lines, as shown in **Table 6-2**.

Table 6-1. Safety Performance Baseline Calculation

Year	Corrosion and Excavation Damage Incidents[1]	Onshore Gathering Miles[2]	Incidents per 1000 Miles[3]
2001	5	17,562	0.285
2002	3	17,426	0.172
2003	1	16,426	0.061
2004	13	17,397	0.747
2005	6	16,220	0.370
Total	**28**	**85,031**	**0.329**

1. Source: Gas Transmission and Gas Gathering Incident Reports, onshore gathering lines corrosion and excavation damage
2. Gas Gathering Annual Report
3. Incidents divided by mileage times 1,000 miles.

Table 6-2. Baseline Incident Rate

Estimated Corrosion and Excavation Damage Incident Rate (per 1,000 miles per year)	Unregulated Higher-Stress, Larger-Diameter Onshore Gas Gathering Mileage	Estimated Corrosion and Excavation Damage Incidents per Year on Unregulated Lines (incidents per year)
0.329	68,749	22.6

Since PHMSA currently regulates only 14,540 miles of onshore gas gathering lines, its consequence data for gathering line incidents is extremely limited. Analysis of this data is especially constrained if limited to only those incidents caused by corrosion and excavation damage. The consequences of individual incidents vary considerably; the consequences of a relatively few incidents cannot be reliably extrapolated to a much larger population. PHMSA does have a significant amount of incident data for gas transmission pipelines, which have been regulated for many years. The characteristics of onshore gas transmission pipelines, in terms of the operating pressures and quantities of gas transported, can be adjusted for Class location and used to approximate the potential consequences from the higher-stress, larger-diameter onshore gas gathering lines that would be covered under the proposed rule. Therefore, PHMSA used reported gas transmission corrosion and excavation damage incident data for onshore Class 1 and Class 2 locations to analyze the expected benefits resulting from the proposed rule.

Appendix E (Table E-7) summarizes the reported safety consequences of corrosion and excavation damage incidents in Class 1 and Class 2 locations reported between 2003 and 2013. The average consequences (fatalities, injuries, and property damage) per incident from the reported data are then applied to the number of incidents expected to occur (29.4 per year) to estimate the baseline consequences per year for the 69,000 miles of higher-stress, larger-diameter onshore gas gathering lines to be newly-regulated under the proposed rule. **Table 6-3** below summarizes these consequences on a per incident basis. Table **6-4** shows the estimation of baseline consequences.

Table 6-3. Average Consequences per Incident on Gas Transmission Systems in Class 1 and 2 Locations from Corrosion or Excavation Damage

Category	Number	Value
Fatalities[1]	0.03	$264,375
Injuries[1]	0.06	$61,68
Evacuations[2]	11.7	$17,517
Other	NA	$175,447
Total	NA	$519,027

Source: See Appendix E (Table E-7)
1. DOT VSL guidance, $9.4M VSL, factor .105 for serious injury.
2. Based on estimate of approximate cost of $1,500 per evacuation.

Table 6-4. Estimated Baseline Consequences Per Year

Incidents	Fatalities[1] (Count)	Injuries[2] (Count)	Evacuation Cost (Count)	Other Incident Costs	Total Costs
22.6	$5,979,708 (0.6)	$1,395,265 (1.4)	$396,209 (264)	$3,968,314	$11,739,495

VSL= Value of Statistical Life
1. Valued using a VSL of $9.4M per Departmental guidance (https://www.transportation.gov/sites/dot.gov/files/docs/VSL2015_0.pdf).
2. Valued using 0.105 times the VSL ($987,000), also per Departmental guidance.

6.3 ESTIMATE OF SAFETY BENEFITS FOR NEWLY-REGULATED TYPE A, AREA 2 PIPELINES

The proposed application of regulations targeting corrosion and excavation damage prevention will result in safety improvements for the 69,000 miles of newly-regulated lines. PHMSA's regulations have been very effective in these areas in the past, reducing the percentage of incidents caused by corrosion and excavation damage on onshore gas transmission pipelines in half since 1995, and more so over the longer-term. PHMSA expects similar improvements due to this rule to commence at the effective date of the proposed rule and occur over time for these newly-regulated lines. The pace of this improvement is expected to be accelerated because of industry's and operators' experiences in applying corrosion and excavation damage best practices as proven compliance strategies on currently regulated facilities.

The regulatory requirements for Type A Area 2 gas gathering segments most closely approximates existing requirements to Type B gathering lines in 49 CFR §192.9(d). PHMSA therefore assumed that the rate of corrosion and excavation damage incidents on Type B gathering lines approximates the incident rate on newly regulated Type A Area 2 lines. Since 2010, there has been only one corrosion or excavation damage related incident on a Type B miles (6,093 miles in 2014). As shown in **Table 6-5**, this equates to an expected incident rate of 0.042 per 10,000 miles.

Table 6-5: Safety Performance of Type B Gas Gathering Pipelines			
Year	Corrosion and Excavation Damage Incidents[1]	Type B Miles[2]	Incidents per 1000 Miles[3]
2010	1	5,344	0.187
2011	0	5,156	0.000
2012	0	3,633	0.000
2013	0	3,664	0.000
2014	0	6,093	0.000
Total	1	23,891	0.042

1. Gas Transmission and Gas Gathering Incident Reports, onshore gathering lines corrosion and excavation damage
2. Gas Gathering Annual Report
3. Incidents divided by mileage times 1,000 miles.

PHMSA assumed that an initial improvement from 0.329 to 0.2 incidents per 1,000 miles. In years 2-5 the incident rate per 1,000 mile falls to 0.1 while periodic components of the rule are implemented. After year 5 the incident rate stabilizes at the historical Type B incident rate. **Table 6-6** shows the expected incidents averted (totaling 271 over the 15-year period; 18 on average annually) and associated benefits for these periods. **Table 6-7** shows the estimated benefits over the 15-year study period.

Table 6-6. Calculation of Safety Benefits, Topic Area 8 (Millions 2015$ per year)						
Period	Incidents Avoided per year	Value of Avoided Fatalities[1]	Injuries[2]	Evacuations[3]	Other Incident Costs[4]	Average Benefits Per Year
Year 1	8.9	$2.3	$0.5	$0.2	$4.6	$7.7
Years 2-5	15.7	$4.2	$1.0	$0.3	$8.2	$13.6
Years 6-15	19.9	$5.3	$1.2	$0.3	$10.3	$17.1

1. Calculated as incidents avoided times VSL ($9.4 million in 2015$).
2. Calculated as incidents avoided times VSL ($9.4 million in 2015$) times 0.105.
3. Calculated as number of evacuations times $1,500 (PHMSA best professional judgment).
4. Calculated as average other incident damages times incidents averted (see Table E-7).

Table 6-5 presents the results of the safety benefits analysis for expanded safety regulation of certain gathering lines.

Table 6-7: Summary of Safety Benefits for Expanded Gathering Line Regulations[1]			
Average Annual (7%)	Total (7%)	Average Annual (3%)	Total (3%)
$9.7	$145.5	$12.5	$188.0

1. Based on expected stream of benefits from Table 6-4. Average annual is total discounted benefits divided by 15 years.

6.4 ESTIMATE OF ENVIRONMENTAL BENEFITS FOR NEWLY-REGULATED TYPE A, AREA 2 PIPELINES

Natural gas transported in gathering pipelines contains the same heat-trapping gases as the gas transmission lines discussed in Section 4.8, with a slightly different set of components and percentage composition. The methodology for calculating the environmental benefit used in Section 4.8 is also utilized for this topic area.

Reduction of the potential number of incidents caused by corrosion and excavation damage, as described in Section 6.2.4, would reduce the amount of natural gas released to the atmosphere and the resultant GHG. The reduction in GHG would reduce the external costs associated with global warming.

Using historical incident data (**Table 6-8**) and assuming the gas composition in gathering lines averages 90% methane and 3% carbon dioxide by volume, PHMSA estimated the amount of natural gas, methane, and carbon dioxide releases that would potentially be avoided each year. When analyzing the historical data, PHMSA considered whether the release ignited, however PHMSA did not identify a gas gathering incident involving ignition or explosion of gas. PHMSA estimated the expected yearly reductions in methane and carbon dioxide released to the atmosphere as GHG using a similar methodology used to estimate the reduction in safety consequences. These amounts are shown in **Table 6-9** for the 15-year study period.

Table 6-8. Type A and Type B Gathering Line Incidents

Year	Incidents	Gas Released (MCF)	Average per Incident
2010	5	5,805	1,161
2011	4	27,413	6,853
2012	4	13,670	3,418
2013	0	0	0
2014	0	0	0
2015	1	25	20
Total	**14**	**46,913**	**3,351**

Source: PHMSA Gas Transmission and Gas Gathering Incident Reports

Table 6-9. Estimate of Reductions in Natural Gas, Methane, and Carbon Dioxide Released[1]

Period	Annual Releases Averted		
	Natural Gas (MCF)[1]	Methane (MCF)[2]	Carbon Dioxide (MT)[3]
Year 1	29,718	26,746	46
Years 2-5	52,755	47,480	82
Years 6-15	66,577	59,920	104
15-Yr Total	**906,512**	**815,861**	**1,411**

MCF = thousand cubic feet
MT = metric tons
1. Calculated as average incidents avoided per year times historical average natural gas releases from gas gathering incidents.
2. Calculated as natural gas released times 0.90.
3. Calculated as natural gas released times 0.03 times 114.4 lbs/MCF carbon dioxide.

To estimate the environmental benefit, PHMSA followed the guidelines established by the Interagency Working Group on SCC. See Appendix B for a detailed discussion of the SCC and SCM. The social cost of GHG emissions reductions calculated for this topic area is for the 15-year study period. PHMSA applied the 3% discounted SCC/SCM values to both the 7% scenario and the 3% discount rate scenarios. The yearly environmental benefit estimates for this topic area are shown in **Table 6-10**. The present value of estimated environmental benefits total approximately $26 million at a 3% discount rate.

Table 6-10. Calculation of Benefits Per Year Based on Reductions in Volumes Emitted (3% Discount Rate)

Period	Methane		Carbon Dioxide		Average Benefits Per Year
	MCF	Average Benefit	Metric Tons	Average Benefit	
Year 1	26,746	$660,888	46	$1,758	$662,646
Years 2-5	47,480	$1,225,579	82	$3,326	$1,228,905
Years 6-15	59,920	$1,877,181	104	$4,799	$1,881,980

MCF = thousand cubic feet
1. Emissions calculated as expected incidents avoided times emission per incident. Values are the average of the product of emissions and the SCC/SCM value over the identified year range

Table 6-11 presents the total climate change benefits due to reductions in gas gathering incident rates.

Table 6-11. Total Environmental Benefits

Pollutant	Emissions	Social Benefit (3%)
Methane (MCF)	815,861	$24,335,016
Carbon dioxide (MT)	1,411	$63,049
Total	**NA**	**$24,398,065**

MCF = thousand cubic feet
MT = metric ton

6.5 ESTIMATE OF BENEFITS FOR OTHER CURRENTLY UNREGULATED GATHERING PIPELINES

Except for the 69,000 miles of higher-stress, larger-diameter lines, the proposed rule would apply only mandatory reporting requirements to the other currently unregulated gathering lines. Thus, no quantifiable reductions in incidents or natural gas releases are projected for those lines. The primary purpose of the proposed new mandatory reporting requirement is to enable PHMSA to gather data to improve its ability to analyze the lines for safety performance and risk. Although benefits are not readily quantifiable, PHMSA expects this information to inform decision-making and affect regulatory and safety outcomes in the future once the existing risks are better understood.

6.6 ADDITIONAL BENEFITS NOT QUANTIFIED

This analysis quantifies benefits from the expected prevention incidents and their consequences. PHMSA did not attempt to quantify other benefits, such as reductions in leaks and failures that do not meet the thresholds for "incident" reporting.

However, not quantified in the benefit-cost analysis for this topic area, PHMSA considers there would likely be additional, qualitative benefits, including:

- Reporting requirements for a substantial new population of gas gathering pipelines would enhance PHMSA's and operators' understanding of gas gathering pipeline risk. More knowledge about these pipeline systems would inform future risk based inspection, regulation, and operator maintenance of these lines.
- Federal safety standards for Type A Area 2 gathering lines would reassure members of the public in gas extraction regions that the segments with the greatest potential consequences are being operated in a safe and responsible manner.
- Pipeline operators may realize additional benefits through improved operating efficiencies realized from less product loss, less energy required to re-transport lost gas.
- The proposed regulations pertaining to the Type A, Area 2 gathering lines would extend the useful life of these pipelines due to the emphasis on prevention, maintenance, and ongoing monitoring.
- Minor and intangible benefits could be realized through greater clarity of regulatory requirements. Consistent definitions among various regulatory agencies, including state and federal pipeline safety agencies, would yield some benefits to operators by eliminating confusion in the interpretation of regulations, particularly for multi-state operators. Agencies responsible for oversight of gathering lines may be more efficient by reducing activities such as answering operator questions, site verification visits, and written clarifications.

7. BENEFIT-COST ANALYSIS PERTAINING TO TOPIC AREA 8 (GAS GATHERING LINES)

This section provides a comparison of benefits and costs for topic area 8 which applies to gas gathering lines. This section also addresses alternatives to the proposed rule in this topic area.

7.1 BENEFITS AND COSTS OF PROPOSED RULE

The costs associated with the proposed safety provisions and the expected safety and environmental benefits from those would apply to the approximately 69,000 miles of newly-regulated gathering lines (Table 3-65) that would be subject to select safety provisions. The costs associated with the reporting provisions would apply to those and the additional 344,000 miles of other currently unregulated gathering lines.

Table 7-1. Summary of Benefits for Topic Area 8 (Millions 2015$)[1]

Benefit	Average Annual (7%)	Total (7%)	Average Annual (3%)	Total (3%)
Safety benefits[2]	$9.7	$145.5	$12.5	$188.0
GHG emissions reductions	$1.6	$24.4	$1.6	$24.4
Total	**$11.3**	**$169.9**	**$14.2**	**$212.4**

1. Total is over 15-year study period; annual is total divided by 15 years.
2. Sum of expected incidents averted times average incident consequence (see Table E-7).

Operators of Type A Area 2 mileage will incur costs to comply with new safety requirements, while operators of all other currently unregulated pipelines will incur relatively small costs to comply with reporting requirements. These costs are summarized in Table 7-2.

Table 7-2 Summary of Compliance and Reporting Costs for Topic Area 8 (Millions 2015$)[1]

Average Annual (7%)	Total (7%)	Average Annual (3%)	Total (3%)
$12.8	$191.6	$15.3	$229.7

1. Total is over 15-year study period; annual is total divided by 15 years.

7.2 CONSIDERATION OF ALTERNATIVES FOR TOPIC AREA 8

With regard to the repealing reference to API RP-80 for defining gathering lines, PHMSA did not consider maintaining the *status quo* to be a viable alternative. The existing definition has proven to be problematic (as described in Section 3.8.A.1) and needs to be addressed.[53]

PHMSA considered an alternative to apply some degree of safety regulations to all unregulated onshore gathering line. This alternative would have applied risk-based rationale to apply selected regulations to pipelines based on a graded approach to address risks appropriate for each category of pipeline. Under this alternative, a very large amount of

[53] ORNL Report, dated Sep 4, 2013, entitled "Review of Existing Federal and State Regulations for Gas and Hazardous Liquid Gathering Lines", ORNL/TM-2013/133.

mileage, 195,000 (over 25 times more than currently regulated) would have substantial incremental compliance costs, while the incremental benefits, in the form of cost of incidents avoided, would be considerably smaller, since the additional line mileage would be smaller, lower pressure, and more rural than line mileage in the proposed rule. Therefore, this alternative is not proposed.

With regard to the proposed reporting requirements, PHMSA considered continuing to exempt the 285,000 miles of gathering lines (that it was not proposing to regulate under the safety provisions of Part 192) from the reporting requirements in Part 191. In the past, PHMSA presumed these gas gathering lines posed a lower level of risk because they are predominantly in rural locations and operated at lower stresses (<20% SMYS). PHMSA has no data with which to substantiate this presumption. In addition, the advent of shale gas production, which utilizes large diameter, high pressure gathering pipeline has invalidated this conventional approach.[54] PHMSA is aware of reports of on unregulated gathering lines, as mentioned earlier in this PRIA. Therefore, some level of reporting is deemed appropriate, especially since these lines represent an estimated 75% of the gathering line mileage in existence. This is a significant portion of the nation’s gas gathering system infrastructure. Therefore, collecting a basic set of information regarding the actual safety performance of these lines would enable assessments of the nature and extent of the potential safety and environmental risks.

[54] Ibid. 45

8. EVALUATION OF UNFUNDED MANDATE ACT CONSIDERATIONS

The UMRA of 1995 requires an impact analysis for rules that that may result in the expenditure by state, local, and tribal governments, in the aggregate, or by the private sector, in exceedance of a specified threshold ($155 million annually, which is $100 million in 1995 dollars, adjusted for inflation). Topic Area 8 of the proposed rule would expand the applicability of onshore gas gathering lines subject to regulation under 49 CFR Parts 191 & 192 to include an estimated 69,000 miles of additional lines covered by select safety and reporting provisions and 344,000 miles covered only by select reporting provisions. These mileages are in Class 1 or Class 2 locations and are not currently regulated. Most of these lines are intrastate pipelines, and PHMSA conservatively assumed that these additional mileages are or would be subject to State oversight. This section provides estimates of the scope and costs of the proposed rule to the States.

There are two aspects of the proposed rule that would impact state resources necessary to provide regulatory oversight:

1) The additional mileage subject to state oversight, which would include, but not be limited to, on-site inspection and enforcement; and,
2) The addition of new operators who are not currently subject to pipeline safety regulation and now must be incorporated within state oversight programs for operator procedures and processes.

8.1 STATE INSPECTION COSTS FOR ADDITIONAL ONSHORE GAS GATHERING LINES

The onshore gas gathering lines that would be newly regulated under the proposed rule fall into two main groups for future state pipeline safety inspection workloads: 1) Type A, Area 2 lines subject to select safety and reporting provisions of PHMSA's pipeline safety regulations; and, 2) other currently unregulated onshore gathering lines subject to select reporting provisions only.

State inspectors typically inspect pipeline systems in 300 to 500-mile segments called "inspection units," however, since the proposed newly-regulated gathering lines are likely to be widely distributed geographically, PHMSA assumed that the typical new inspection unit would be half that size, or between 150- and 250-miles. PHMSA estimated that field inspection of an inspection unit from the first group of lines typically would consist of three person-days in the field, followed by two person-days of office time to document the inspection and prepare any resulting enforcement action recommendations. And, further, PHMSA estimated that each inspection unit is on a two-year cycle of inspections. For the second group, no field inspections are required as no safety provisions would apply.

8.2 STATE INSPECTION COSTS FOR FIRST-TIME OPERATORS OF REGULATED ONSHORE GAS GATHERING LINES

Pipeline operators undergo company headquarters inspections in which the state pipeline safety inspection staff examines the operator's policies, procedures, and processes associated with compliance to pipeline safety regulations. Operators with added gathering line mileage under the proposed rule, but with pre-existing regulated lines, will have already undergone such inspections and already be in the state's routine, corporate-level inspection cycle. Operators without pre-existing regulated lines would undergo an initial company headquarters inspection, and thereafter be incorporated within the state's master list of operators subject to oversight. Again, the scope and extent of these company headquarters inspections would depend on which of the two main groups of pipelines is involved, namely, those that would be subject to the safety and reporting provisions, or those that would be subject only to the reporting provisions. For operators that have Type A, Area 2 pipelines, PHMSA estimated that a first-time company headquarters inspection would consist of five person-days on-site, plus two person-days of follow-up documentation and processing. PHMSA estimated that each new operator would be on a five-year cycle of company headquarters inspections thereafter, and assumed the initial inspections would be conducted and distributed evenly, over a period of three years.

8.3 ESTIMATED COSTS FOR STATE INSPECTIONS OF NEWLY-REGULATED GATHERING LINES SUBJECT TO SAFETY INSPECTION

Table 8-1 lists the estimated mileages of the gathering pipelines that would become newly inspected under the proposed rule, including an estimate of the number of new inspection units that would need to be created.

Table 8-1. Mileages, Inspection Units, and New Operators for the Newly-Regulated Gathering Lines

Mileage Group Descriptions	Estimate of Miles	Estimated of Inspection Units[1]
Type A, Area 2	**68,749**	**344**
Operator group 1	2,200	11
Operator group 2	66,549	333

1. Calculated as miles divided by 200.

Unit costs to the states are estimated based on the actual 2012 expenses for gas and hazardous liquid programs, as well as on the actual total number of person-days allotted within the states and reported to PHMSA in states annual reports. Table 8-2 shows these values.

Table 8-2. Unit Cost for State Pipeline Safety Programs in 2012

Total State Program Expenses	Estimated Number of Inspection-Days	Unit Cost per Inspection-Day
$50,202,484	39,473	$1,272

Source: State reports

8.3.1 FIELD INSPECTION COSTS

Routine field inspection costs are estimated to total $2.26 million, split evenly over two years for a two-year recurring inspection cycle, yielding approximately $1.13 million per year (**Table 8-3**).

Table 8-3. Estimated Routine Field Inspection Costs to the States for Newly-Regulated Gathering Lines Subject to Safety Provisions (Type A, Area 2)			
Estimated Inspection Units	**No. of Inspection-Days per Unit**	**Total Field Inspection-Days**	**Total Field Inspection Costs ($ / 2 years)**
356	5	1,780	$2,264,160

8.3.2 HEADQUARTERS INSPECTION COSTS

Consistent with Section 3.8.2.4., the proposed rule is expected to result in newly-regulated operators. **Table 8-4** provides estimates of company headquarters inspection costs for the states for different assumptions regarding the specific number of operators. From estimates ranging from 75 to 125 newly regulated operators, estimated total annual costs would range from approximately $0.7 million to $1.1 million, distributed equally over the operators' first three years in the program ($0.2 million to $0.4 million per year), and then recur annually at the reduced rate of $0.1 million to $0.2 million per year since they then recur on a 5-year cycle..

Table 8-4. Company Headquarter Inspection Costs to the States for Newly-Regulated Operators Subject to Safety Provisions					
No. of Operators	**No. of Inspection-Days per Operator**	**Total HQ Inspection-Days**	**Total HQ Inspection Costs[1]**	**Cost per Year, Initial 3-Year Cycle[2]**	**Cost per Year, Recurring 5-Year Cycle[3]**
75	7	525	$667,800	$222,600	$133,560
100	7	700	$890,400	$296,800	$178,080
125	7	875	$1,113,000	$371,000	$222,600

HQ = headquarters
1. Inspection-days times unit cost per day ($1,272, see Table 8-2).
2. Total divided by 3.
3. Total divided by 5.

8.3.3 TOTAL INSPECTION COSTS

Combining the costs in Table 8-3 and Table 8-4 the total estimated cost to the states for Topic Area 8 of the proposed rule would not exceed approximately $1.5 million per year (**Table 8-5**).

Table 8-5. Total Annual Costs to the States for Newly-Regulated Gathering Lines Subject to Safety Provisions, First Three Years (Millions)		
Field Inspections	**Company HQ Inspections[1]**	**Total**
$1.1	$0.2 - $0.4	$1.3 - $1.5

1. Based on between 75 and 125 newly regulated operators, for example.

8.3.4 SUMMARY

Based on estimated costs to states not exceeding $1.5 million per year, under plausible assumptions regarding the number newly regulated operators, the magnitude of potential impact is significantly less than the criteria in the Act (over $155 million per year, in current year dollars).

APPENDIX A SUPPLEMENTAL CALCULATIONS FOR TOPIC AREA 1 COST ESTIMATES

This appendix shows the estimation of the impacted HCA mileage for MAOP verification provisions of Topic Area 1. Specifically it estimates the HCA mileage that operates at stresses greater than 30% of SMYS, and between 20-30% of SMYS and is certified under 49 CFR §619(c).[55] **Tables A-1** and **A-2** calculate the impacted mileage for those two populations of pipeline segments based on operators annual report submissions.

A-1. Calculation of HCA Mileage Operating at Pressure Greater than 30 Percent SMYS					
Location	**Onshore Gas Transmission Miles[1]**	**HCA Mileage[2]**	**Total >30% SMYS**	**% >30% SMYS**	**HCA >30% SMYS**
Interstate					
Class 1	160,381	62	145,656	91%	56
Class 2	17,811	23	14,918	84%	19
Class 3	13,925	439	11,319	81%	357
Class 4	29	0	16	55%	0
Total	192,146	524	171,908	89%	469
Intrastate					
Class 1	72,254	13	56,034	78%	10
Class 2	12,820	18	9,018	70%	13
Class 3	19,726	749	11,876	60%	451
Class 4	880	5	430	49%	3
Total	105,680	786	77,358	73%	575
Total Onshore					
Class 1	232,635	75	201,690	87%	65
Class 2	30,631	41	23,936	78%	32
Class 3	33,652	1,189	23,194	69%	819
Class 4	908	6	446	49%	3
Total	297,826	1,310	249,266	84%	1,096
Source: 2014 PHMSA Annual Report 1. Part K 2. Part Q GF HCA 3. Part K					

A-2. Calculation of HCA Mileage Operating at Pressure 20-30% SMYS					
Location	**Onshore Gas Transmission Miles[1]**	**HCA Mileage[2]**	**Total 20-30% SMYS**	**% >30% SMYS**	**HCA >30% SMYS**
Interstate					
Class 1	160,381	62	7,975	5%	3
Class 2	17,811	23	1,433	8%	2
Class 3	13,925	439	1,305	9%	41

[55] Commonly referred to as the "Grandfather Clause"

A-2. Calculation of HCA Mileage Operating at Pressure 20-30% SMYS					
Location	**Onshore Gas Transmission Miles[1]**	**HCA Mileage[2]**	**Total 20-30% SMYS**	**% >30% SMYS**	**HCA >30% SMYS**
Class 4	29	0	9	32%	0
Total	192,146	524	10,722	6%	46
Intrastate					
Class 1	72,254	13	8,245	11%	1
Class 2	12,820	18	2,737	21%	4
Class 3	19,726	749	5,610	28%	213
Class 4	880	5	427	49%	3
Total	105,680	786	17,019	16%	221
Total Onshore					
Class 1	232,635	75	16,220	7%	5
Class 2	30,631	41	4,170	14%	6
Class 3	33,652	1,189	6,914	21%	254
Class 4	908	6	436	48%	3
Total	297,826	1,310	27,740	9%	267

Source: 2014 PHMSA Annual Report.
1. Part K
2. Part Q GF HCA
3. Part K

APPENDIX B SOCIAL COST OF GREENHOUSE GAS EMISSIONS

This appendix provides estimates of the social cost of carbon (SCC) and methane (SCM). In this analysis, PHMSA uses these values to estimate costs associated these greenhouse gas (GHG) emissions from the blowdown of gas during compliance activities (primarily methane) and released as a result of incidents [which may also include carbon dioxide (CO_2) if the gas ignites].

The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year [Interagency Working Group (IWG), 2015].[56] The IWG on SCC developed estimates of these damages to allow agencies to incorporate the social benefits of reducing carbon dioxide (CO_2) emissions into cost-benefit analyses of regulatory actions that impact cumulative global emissions. The estimates include, but are not limited to, changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change. IWG (2015) calculates the SCC using discount rates of 2.5%, 3%, and 5%. **Table B-1** shows the SCC each year, which is applied to emission changes for the relevant years to estimate the dollar value of GHG impacts from CO_2 emissions.

Marten et al. (2014)[57] used the same models and assumptions that underlie the current IWG SCC estimates (IWG 2013; updated 2015) to develop a unit SCM [see EPA (no date)[58] for detailed discussion of the limitations of using the global warming potential (GWP) approach previously used by some federal agencies to monetize the costs of methane releases for inclusion in benefit-cost analyses].[59] **Table B-2** shows the SCM based on Marten et al., (2014).

Tables B-3 through **B-5** provide the estimated social costs and benefits of the proposed rule due to changes in GHG emissions. Note that Table B-3 and B-4 only illustrate the low

[56] Interagency Working Group on Social Cost of Carbon (IWG), United States Government. 2015. Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. Revised July 2015.

[57] Marten, A.L., E.A. Kopits, C.W. Griffiths, S.C. Newbold, and A. Wolverton. 2014. Incremental CH4 and N20 Mitigation Benefits Consistent with the US Government's SC-CO2 Estimates. Climate Policy.

[58] U.S. Environmental Protection Agency (EPA). No date. Whitepaper on Valuing Methane Emissions Changes in Regulatory Benefit-Cost Analysis, Peer Review Charge Questions, and Responses. http://www3.epa.gov/climatechange/pdfs/social%20cost%20methane%20white%20paper%20application%20and%20peer%20review.pdf

[59] In brief, a potential method for approximating the SCM is to convert the units of methane to units of CO_2-equivalent using the GWP, then applying the SCC. However, methane is more potent but has a much shorter life than CO2, resulting in more impacts in the near term, which would be discounted less heavily than impacts occurring further out in the future. Additionally, methane does not have the positive fertilization impacts that CO2 does. Several recent studies found that GWP-weighted benefit estimates for methane are likely to be lower than the estimates derived using directly modeled social cost estimates for these gases. Gas comparison metrics, such as the GWP, are designed to measure the impact of non-CO_2 GHG emissions relative to CO_2 at a specific point along the pathway from emissions to monetized damages and this point may differ across measures. Because these and other variations in the timing and nature of impacts are not captured by simply multiplying the SCC by GWP, IWG (2010) recommends against using this approach to value non-CO_2 GHG.

Interagency Working Group on Social Cost of Carbon (IWG), United States Government. 2010. Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.

incidents averted scenario for Topic Area 1.

Table B-1. Social Cost of Carbon Based on IWG (2015)[1]

Year	SCC (per metric ton CO2; 2007$)	SCC (per metric ton CO2; 2015$)
2015	$36	$41
2016	$38	$43
2017	$39	$45
2018	$40	$46
2019	$41	$47
2020	$42	$48
2021	$42	$48
2022	$43	$49
2023	$44	$50
2024	$45	$51
2025	$46	$53
2026	$47	$54
2027	$48	$55
2028	$49	$56
2029	$49	$56
2030	$50	$57

Source:
1. Based on 3% discount rate.
CO_2 = carbon dioxide
IWG = The Interagency Working Group on Social Cost of Carbon
SCC = social cost of carbon

Table B-2. Social Cost of Methane Based on Marten et al., (2014)

Year	SC per metric ton methane (2007$)	SC per MCF methane (2015$)
2015	$1,100	$24
2016	$1,120	$25
2017	$1,140	$25
2018	$1,160	$26
2019	$1,180	$26
2020	$1,200	$26
2021	$1,240	$27
2022	$1,280	$28
2023	$1,320	$29
2024	$1,360	$30
2025	$1,400	$31
2026	$1,440	$32
2027	$1,480	$33
2028	$1,520	$34

Table B-2. Social Cost of Methane Based on Marten et al., (2014)		
Year	**SC per metric ton methane (2007$)**	**SC per MCF methane (2015$)**
2029	$1,560	$34
2030	$1,600	$35
Source: Marten, A.L., E.A. Kopits, C.W. Griffiths, S.C. Newbold, and A. Wolverton. 2014. Incremental CH_4 and N_20 Mitigation Benefits Consistent with the US Government's SC-CO_2 Estimates. Climate Policy. Inflated to 2015 based on 2015 average CPI of 237.0 SC = Social cost MCF = 1,000 ft^3 of a gas at standard temperature and pressure		

Table B-3. Total Social Cost of GHG Emissions due to Pressure Test and ILI Upgrade related Blowdowns (3%)

Year	Methane Emissions (MCF)	SCM (3%)	C0₂ Emissions (lbs)	C0₂ Emissions (metric tons)	SCC	Social Cost of GHG Emissions
2016	65,012	$1,606,424	96,686	44	$1,667	$1,608,090
2017	65,012	$1,635,110	96,686	44	$1,710	$1,636,820
2018	65,012	$1,663,796	96,686	44	$1,754	$1,665,550
2019	65,012	$1,692,482	96,686	44	$1,798	$1,694,280
2020	65,012	$1,721,168	96,686	44	$1,842	$1,723,010
2021	65,012	$1,778,540	96,686	44	$1,842	$1,780,382
2022	65,012	$1,835,913	96,686	44	$1,886	$1,837,798
2023	65,012	$1,893,285	96,686	44	$1,930	$1,895,215
2024	65,012	$1,950,657	96,686	44	$1,974	$1,952,631
2025	65,012	$2,008,029	96,686	44	$2,017	$2,010,047
2026	65,012	$2,065,402	96,686	44	$2,061	$2,067,463
2027	65,012	$2,122,774	96,686	44	$2,105	$2,124,879
2028	65,012	$2,180,146	96,686	44	$2,149	$2,182,295
2029	65,012	$2,237,518	96,686	44	$2,149	$2,239,667
2030	65,012	$2,294,891	96,686	44	$2,193	$2,297,084
Total	975,180	$28,686,134	1,450,287	658	$29,076	$28,715,211

CO_2 = carbon dioxide
GHG = greenhouse gas
lbs = pounds
MCF = thousand cubic feet
MT = metric ton
SCC = social cost of carbon
SCM = social cost of methane

Table B-4. Social Benefit of GHG Emissions Reductions, Topic Areas 1-7, Discounted at 3% (2015$)

Year	Methane Emissions (MCF)	SCM (3%)	C0₂ Emissions (lbs)	C0₂ Emissions (MT)	SCC	GHG Reduction Benefit
2016	256,006	$6,325,820	1,926,905	874	$33,213	$6,359,033
2017	256,006	$6,438,781	1,926,905	874	$34,087	$6,472,868
2018	256,006	$6,551,742	1,926,905	874	$34,961	$6,586,703
2019	256,006	$6,664,703	1,926,905	874	$35,835	$6,700,538
2020	256,006	$6,777,664	1,926,905	874	$36,709	$6,814,373
2021	256,006	$7,003,587	1,926,905	874	$36,709	$7,040,296
2022	256,006	$7,229,509	1,926,905	874	$37,583	$7,267,092
2023	256,006	$7,455,431	1,926,905	874	$38,457	$7,493,888
2024	256,006	$7,681,353	1,926,905	874	$39,331	$7,720,684
2025	256,006	$7,907,275	1,926,905	874	$40,205	$7,947,480
2026	256,006	$8,133,197	1,926,905	874	$41,079	$8,174,276
2027	256,006	$8,359,119	1,926,905	874	$41,953	$8,401,073
2028	256,006	$8,585,042	1,926,905	874	$42,827	$8,627,869
2029	256,006	$8,810,964	1,926,905	874	$42,827	$8,853,791
2030	256,006	$9,036,886	1,926,905	874	$43,701	$9,080,587
Total	3,840,090	$112,961,073	28,903,579	13,110	$579,479	$113,540,552

CO_2 = carbon dioxide
GHG = greenhouse gas
lbs = pounds
MCF = thousand cubic feet
MT = metric ton
SCC = social cost of carbon
SCM = social cost of methane

Table B-5. Social Benefits of Avoided Gathering Line GHG Emissions (3%)

Year	Avoided CH_4 emissions (MCF)	SCM (3%)	Avoided C02 Emissions(lbs)	C02 Emissions (MT)	SCC	Social Cost of GHG Emissions
2016	26,746	$660,888	101,992	46	$1,758	$662,646
2017	47,480	$1,194,154	181,055	82	$3,203	$1,197,357
2018	47,480	$1,215,104	181,055	82	$3,285	$1,218,389
2019	47,480	$1,236,054	181,055	82	$3,367	$1,239,421
2020	47,480	$1,257,004	181,055	82	$3,449	$1,260,453
2021	59,920	$1,639,229	228,494	104	$4,353	$1,643,582
2022	59,920	$1,692,107	228,494	104	$4,457	$1,696,564
2023	59,920	$1,744,985	228,494	104	$4,560	$1,749,546
2024	59,920	$1,797,864	228,494	104	$4,664	$1,802,528
2025	59,920	$1,850,742	228,494	104	$4,768	$1,855,510
2026	59,920	$1,903,620	228,494	104	$4,871	$1,908,492
2027	59,920	$1,956,499	228,494	104	$4,975	$1,961,474
2028	59,920	$2,009,377	228,494	104	$5,078	$2,014,456
2029	59,920	$2,062,255	228,494	104	$5,078	$2,067,334
2030	59,920	$2,115,134	228,494	104	$5,182	$2,120,316
Total	815,861	$24,335,016	3,111,149	1,411	$63,049	$24,398,065

CH_4 = methane
CO_2 = carbon dioxide
GHG = greenhouse gas
lbs = pounds
MCF = thousand cubic feet
MT = metric ton
SCC = social cost of carbon
SCM = social cost of methane

APPENDIX C RATE OF INCIDENT PREVENTION AS A FUNCTION OF ASSESSMENT MILEAGE

PHMSA estimated benefits for Topic Area 1 as the number of miles assessed times the rates that defects are detected and the proportion of those defects which would evolve into pipe failures if they are not repaired. This appendix shows the estimation of the defect discovery rate per mile based on historical integrity assessment performance data reported in gas transmission and hazardous liquid annual reports.

C.1 PREVENTION OF INCIDENTS BY IN-LINE INSPECTION

The cost and benefit analysis for topic area 1 is based in part on an estimate of the number of defects that would be discovered and remediated (repaired) as a result of the integrity assessments required by the proposed rule. There are two baselines that apply, depending on the type of pipelines segments to which a given topic area applies. (1) Pipe that has not been previously assessed and remediated in accordance with integrity management requirements (Subpart O of Part 192). This would predominantly include pipe located in the proposed MCA in Class 1 and 2 locations. (2) Pipe that has been previously assessed and remediated in accordance with integrity management requirements (Subpart O of Part 192). This would include pipe in HCAs and most class 3 and 4 pipe in proximity to HCAs that would reasonably be expected to have been assessed in conjunctions with HCA assessments.

Existing requirements for gas operators do not include all of the proposed repair criteria. However, the hazardous liquid (HL) pipeline IM rule has always included many (but not all) of the proposed repair criteria. Because the existing HL repair criteria are similar to the proposed gas repair criteria, and PHMSA has reliable data from HL operators for reported repairs, the HL repair data can be used as a proxy for an expected defect discovery rate for GT pipelines under the proposed rule. Causes of GT pipeline accidents and the vulnerability of pipelines to threats and deleterious environments are very similar to HL pipelines. For the purpose of this analysis, it is reasonable to apply the HL repair data to GT pipelines that have not been previously assessed.

However, some pipelines that would require an assessment under the proposed rules have already been assessed because they are located in an HCA. To account for the defects previously discovered and remediated under Part 192, Subpart O, PHMSA used the difference between the HL discovery rate and the GT historical discovery rate. In making this comparison, PHMSA used data from 2004-2009 because the baseline assessment periods for both HL and GT IM programs overlapped during these years and data is more directly comparable.

PHMSA used an annual average of each of the defect discovery rates used in the analysis. As shown in the tables below, mileage assessed has generally trended down while the rates at which defects are discovered have gone up. The latter is not unexpected since PHMSA expects that both integrity assessment accuracy and defects due to metal fatigue or corrosion may increase over time. The annual average retains earlier data while giving more weight to more recent years. This method likely more accurately estimates current and future performance of integrity assessment technologies.

Table 4-1 in the body of the report summarizes the defect discovery rates used in this analysis. PHMSA applied an average of the historical hazardous liquid defect discovery rates between 2004 and 2009 as an estimate of the discovery rate on non-HCA pipelines which have not previously been assessed (including MCA). These rates are 0.10 immediate repair conditions per mile 0.10 per mile and 0.49 scheduled repair conditions per mile. For HCA segments assessed PHMSA applied the average difference between the hazardous liquid defect discovery rate and the gas transmission discovery rate over the same period. This reflects the marginal change due to the difference in repair and assessment criteria. For HCA assessment miles these rates are 0.05 immediate repair conditions per mile and 0.38 scheduled repair conditions per mile.

The number of incidents averted is estimated by the conditions that are discovered and repaired. As stated in ASME B31.8S, Section 7.2, immediate conditions are those that indicate the defect is at the failure point, with little, if any, safety margin remaining. Immediate conditions could be discovered through assessments using ILI or direct assessment. Even though immediate conditions represent defects in the pipe that are at the failure point, experience has shown that not all of those defects would fail before the next integrity assessment. For purposes of this analysis, PHMSA assumed that between 3.0%-12.5% of the immediate conditions discovered and repaired represent incidents averted.

Conditions requiring one-year and scheduled repairs occur at a higher rate than immediate conditions. Even though these conditions do not meet the criteria for an immediate repair, they do reduce the strength of the pipe and make the pipe more susceptible to failure, especially in the presence of other interacting defects or threats (such as external force, third-party damage, or repeated pressure fluctuations). There have been cases where defects that did not meet the immediate repair criteria have failed in service before the defect was repaired. However, those are less likely than an immediate condition to lead to failure before the next integrity assessment. In the absence of specific data, for purposes of this analysis, PHMSA assumed that between 0.3%-0.5% of non-immediate conditions discovered and repaired represent incidents averted.

Using the data in **Table C-1** and **Table C-2**, and the above assumptions, PHMSA estimated the rate of incidents averted (prevented) by the discovery and repair of immediate conditions and scheduled conditions for both previously assessed and previously unassessed segments, shown in the figures below. For HCA pipe, PHMSA used the incident prevention rate for previously assessed pipe. For non-HCA and MCA pipe, PHMSA used the defect discovery rate for previously unassessed pipe.

Table C-1. Estimated Immediate Condition Repair Rates for Previously Unassessed Pipe and Previously Assessed Pipe

	Hazardous Liquid Integrity Management Immediate Repair Rate			Gas Transmission Integrity Management Immediate Repair Rate			GT Estimated Immediate Repair Rate for Previously Assessed Pipe
Year	Total HL Assessment Miles	HL HCA Immediate Repairs	HL Immediate Repair Rate[1]	Total GT Assessment Miles	GT HCA Immediate Repairs	GT HCA Immediate Repair Rate	
2004	65,565	1,701	0.026	3998	104	0.026	0.000
2005	17,501	1,369	0.078	2906	261	0.090	-0.012
2006	12,411	941	0.076	3500	158	0.045	0.031
2007	9,240	880	0.095	4663	258	0.055	0.040

Table C-1. Estimated Immediate Condition Repair Rates for Previously Unassessed Pipe and Previously Assessed Pipe

Year	Hazardous Liquid Integrity Management Immediate Repair Rate			Gas Transmission Integrity Management Immediate Repair Rate			GT Estimated Immediate Repair Rate for Previously Assessed Pipe
	Total HL Assessment Miles	HL HCA Immediate Repairs	HL Immediate Repair Rate[1]	Total GT Assessment Miles	GT HCA Immediate Repairs	GT HCA Immediate Repair Rate	
2008	5,916	888	0.150	2858	181	0.063	0.087
2009	3,372	660	0.196	3288	144	0.044	0.152
Average rate[2]	NA	NA	**0.104**	NA	NA	0.054	**0.050**

Source: Gas Transmission and Hazardous Liquid Annual Reports
GT = gas transmission
HCA = high consequence area
HL = hazardous liquid
NA = not applicable
1. Assumed gas transmission repair rate for previously unassessed pipe.
2. Average of 2004-2009 rates

Table C-2. Estimated Scheduled Condition Repair Rates for Previously Unassessed Pipe and Previously Assessed Pipe

Year	Hazardous Liquid Integrity Management Scheduled Condition Repair Rate						Gas Transmission Integrity Management Scheduled Repair Rate			GT Estimated Scheduled Repair Rate for Previously Assessed Pipe
	Total HL Assessed Miles	HL HCA 60-Day Repairs	HL 60-day Repair Rate	HL HCA 180-day Repairs	HL 180-day Repair Rate	HL Total HCA Scheduled Repair Rate[1]	Total Assessed Miles	Total Scheduled Repairs	Scheduled Repair Rate	
2004	65565	647	0.0099	3178	0.0485	0.058	3,998	599	0.150	-0.091
2005	17501	1109	0.0634	5278	0.3016	0.365	2,907	378	0.130	0.235
2006	12411	861	0.0694	2748	0.2214	0.291	3,501	344	0.098	0.193
2007	9240	580	0.0628	2139	0.2315	0.294	4,663	452	0.097	0.197
2008	5916	1022	0.1728	4037	0.6824	0.855	2,858	252	0.088	0.767
2009	3372	454	0.1346	3088	0.9158	1.050	3,288	266	0.081	0.970
Avg. rate[2]	NA	NA	0.0855	NA	0.400	**0.486**	NA	NA	0.107	**0.378**

Source: Gas Transmission and Hazardous Liquid Annual Reports
GT = gas transmission
HCA = high consequence area
HL = hazardous liquid
NA = not applicable
1. Assumed gas transmission repair rate for previously unassessed pipe.
2. Average of 2004-2009 rates

C.2 PREVENTION OF INCIDENTS BY PRESSURE TESTING

Table C-3 shows annual report data for 2010- 2013.

Table C-3. Pressure Test Failures 2010-2013

Year [1]	Miles Pressure Tested	Failures both in and out HCA	Test Failure Rate per Mile
2013	1,502	54	0.0360
2012	2,078	52	0.0250
2011	1,687	71	0.0421
2010	1,393	51	0.0366
Average Rate[2]	NA	NA	0.0349

1. Operators were not required to report pressure test failures prior to 2010.
2. Average of 2010-2013 rates

Table C-3 indicates an average annual rate of 0.0349 test failures/mile, with a mean/standard deviation ratio of 4.9. PHMSA applied this discovery rate for both previously assessed HCA miles and previously unassessed non-HCA miles For purposes of this analysis, PHMSA assumes that between one out of 3 (33%) and one half (50%) of historical pressure test failures represent incidents averted.

APPENDIX D CONSEQUENCES OF SAN BRUNO INCIDENT

The CPUC proposed a $1.4B fine[60] and the Department of Justice filed an indictment,[61] in which PGE is alleged to have violated numerous integrity management regulations (49 CFR Part 192, Subpart O). PHMSA is proposing to provide greater emphasis on those regulations through the proposed changes in Topic Area 2. Those proposed regulatory provisions are not changes to existing requirements, thus neither costs nor benefits are estimated for those proposals. However, many of the issues being addressed by the proposed regulations in Topic Areas 1 and 3 are new requirements designed to address the lessons learned, causes, and contributing factors to the San Bruno incident of September 9, 2010. Those major causes and contributing factors, as identified by NTSB, related to the proposed regulations in topic area 1 are summarized as follows:

1. "The National Transportation Safety Board determines that the probable cause of the incident was the Pacific Gas and Electric Company's (PG&E) (1) inadequate quality assurance and quality control in 1956 during its Line 132 relocation project, which allowed the installation of a substandard and poorly welded pipe section with a visible seam weld flaw that, over time grew to a critical size, causing the pipeline to rupture during a pressure increase stemming from poorly planned electrical work at the Milpitas Terminal …" ─ NTSB

   The Management of Change regulations proposed in Topic Area 3 are designed to address the process for change control to prevent unauthorized material substitutions such as the substandard pipe section installed in 1956 and the poorly planned electrical work at Milpitas Terminal. The proposed integrity verification requirements in Topic Area 1 are designed to find and fix substandard pipe segments such as were discovered to have failed at San Bruno, including requirements for establishing material properties and related records.

2. "Contributing to the incident were the California Public Utilities Commission's (CPUC) and the U.S. Department of Transportation's exemptions of existing pipelines from the regulatory requirement for pressure testing, which likely would have detected the installation defects." ─ NTSB

The proposed regulations in Topic Area 1 include repeal of exemptions for pressure testing for pipe in HCAs or MCAs, and the conduct of assessments or other measures by which operators must verify the MAOP of the pipeline segment for which pressure testing was previously exempt, including requirements for establishing material properties and related records.

The NTSB issued numerous specific recommendations to address the causes and contributing factors of the San Bruno incident. PHMSA described those NTSB recommendations and how they influenced the scope of the proposed rule in Sections 1, 2, and 3.

[60] California Public Utilities Commission, Press Release, September 2, 2014, "CPUC JUDGES ISSUE DECISIONS IN PG&E PIPELINE CASES, LEVYING LARGEST SAFETY RELATED PENALTY EVER BY CPUC"
[61] http://oag.ca.gov/news/press-releases/attorney-general-kamala-d-harris-issues-statement-federal-indictment-pge

PHMSA incident data includes the number of fatalities and serious injuries (that require overnight hospitalization), and the value of property damaged as a result of the incident (such as cost to repair or replace homes damaged, damage to the operator's property, etc.). Also included are other consequences, including the operator's costs associated with responding to the emergency, the cost of gas lost, number of persons evacuated, and the duration of system shutdown. PG&E, in its final incident report for the San Bruno incident, reported 8 fatalities, 51 injuries, and no evacuations, along with $100,000 in property damage, $0 cost for emergency response, $263,000 in the cost of lost gas, and $375M in other damages.

However, operators are not required to include in incident reports all consequence costs, such as the cost of public safety and first responders, cost of evacuation, lawsuit judgments/settlements, legal fees, cost of repair to public infrastructure, cost of investigation, evaluation of other pipeline segments, cost of implementing orders from regulatory agencies in response to the incident, lost productivity, lost revenue, and other extraordinary costs attributable to the incident, many of which are not legally settled or finalized until years after the incident. Such costs are often difficult to discover, since settlement information is sometimes not disclosed, but may be incurred nonetheless. However, in the case of severe incidents with intense media coverage, additional consequential cost data is often discoverable, especially if the operator is a publically traded company. If known, with a reasonable degree of certainty, such information can be used to more accurately estimate and monetize the consequences of a given incident. Relying solely on PHMSA incident report data would understate the true consequential costs of severe incidents. For example, in the case of the San Bruno incident, the Dow Jones Newswire[62] reported that, as of February 21, 2013, the cost incurred by PG&E as a result of the San Bruno incident exceeded $1.9B and was estimated to total approximately $3B. This information is reflected in PG&E annual reports, which itemize the unrecoverable costs PG&E charged for the San Bruno incident beginning in 2010. The cumulative costs through 2013 total $2.594B (excluding fines and penalties). PG&E was expected to continue to pay additional costs in 2014, as explicitly reported in the company's 2013 annual report, and in subsequent years in accordance with its CPUC mandated Pipeline Safety Enhancement Plan.

Accordingly, PHMSA estimated the consequences of the San Bruno incident as follows.

1. **Loss of life, injuries, and property damage to the public.** Most of the lawsuits from individuals harmed by the incident have been settled. As reported by PG&E in its annual reports for 2010,[63] 2011,[64] 2012,[65] and 2013,[66] PG&E charged a total of $565M for those settlements. Subtracting the value of statistical life for 8 deaths and 51 injuries, results in an estimate of other damages to those individuals harmed by the incident of approximately $508M.
2. **Cost of gas lost.** PG&E's incident report stated that the value of gas lost as a result

[62] Dow Jones Newswires, PG&E Faces Continued Costs, Uncertainty After San Bruno Pipeline Blast, February 21, 2013, 15:07ET; http://www.nasdaq.com/aspx/stockmarketnewsstoryprint.aspx?storyid=pge-faces-continued-costs-uncertainty-after-san-bruno-pipeline-blast-20130221-01304
[63] PG&E Corporation and Pacific Gas and Electric Company, 2010 Annual Report
[64] PG&E Corporation and Pacific Gas and Electric Company, 2011 Annual Report
[65] PG&E Corporation and Pacific Gas and Electric Company, 2012 Annual Report
[66] PG&E Corporation and Pacific Gas and Electric Company, 2013 Annual Report

of the incident was $263,000.

3. **Emergency response (PG&E).** Although PG&E did not report any costs for emergency response, it deployed SCADA center crews, dispatched staff to the scene, deployed onsite crews and field supervisors, activated the San Carlos operations emergency center command post, and activated its San Francisco headquarters operations emergency center command post. PHMSA estimated the cost of PG&E emergency response for the San Bruno incident to be approximately $250,000.

4. **Emergency response (government and public) and post-incident recovery.** Operators are not required to report the government and public response to the incident. However, reliable reports[67] and studies[68] identified that approximately 600 firefighters, 325 law enforcement, 90 ground apparatus, 4 air tankers,[69] 2 air attack planes, and 1 helicopter, responded to the incident within the first 50 hours. PG&E funded a $50M trust for the City of San Bruno[70] explicitly to cover any costs directly related to the fire response and the cost of recovery. The trust also provides funds for infrastructure repair and replacement, additional government and responder staffing costs, costs of participation in regulatory proceedings, and the costs of legal and other experts as needed.

5. **Disaster relief.** As reported by PG&E in its 2010 annual report (p. 11), "PGE [PG&E] provided $63 million of costs incurred to provide immediate support to the San Bruno community, re-inspect the Utility's natural gas transmission lines, and to perform other activities following the incident." Most of these disbursements were direct disbursements to affected parties immediately after the incident in the form of checks, gift cards, emergency assistance, charitable contributions, natural gas bill relief, and miscellaneous emergency support (e.g., PG&E community support webpage). In addition, the American Red Cross, provided $1,587,210 in disaster relief[71] and the Glenview Fire Relief Fund provided $400,000 in disaster relief.[72]

6. **Evacuations.** PG&E reported no evacuations as a result of the incident, but NTSB Pipeline Incident Report PAR-11-01 identified that 300 houses were evacuated. PHMSA considers these evacuation costs to be included in the disaster relief item above.

7. **Consequences of system shutdown and mandatory operating pressure reduction (Urgent NTSB Recommendation P10-5/CPUC Order R L-403).** The California Public Utilities Commission (CPUC) ordered PG&E to impose a mandatory pressure reduction on several of its pipeline systems, in the wake of the San Bruno incident, and required that PG&E obtain CPUC approval before increasing pressure.[73] NTSB

[67] National Transportation Safety Board, Pipeline Incident Report, Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010, NTSB/PAR-11/01
[68] University of Delaware Disaster Research Center, Report on San Bruno Disaster, Final Project Report #56, 2012.
[69] California Fire News (blog). September 9, 2010
[70] Irrevocable Trust Agreement Dated March 24, 2011, http://www.sanbruno.ca.gov/Glenview_crestmoortrust.html
[71] American Red Cross, San Bruno Explosion Response, Summary Report November 2013.
[72] *Ibid*. 53
[73] Letter from Paul Clannon, Executive Director, California Public Utilities Commission to Christopher Johns, President, Pacific Gas and Electric Company, dated September 13, 2010, "Safety Response to the San Bruno Pipeline Explosion"

also issues an urgent recommendation that CPUC provide oversight to PG&E while PG&E performed records search and analysis to verify or determine the safe MAOP for its pipelines. As a result, a portion of PG&E's Line 132 between San Andreas Station and Healy Station was filled with concrete and abandoned in place. The remainder of Line 132, as well as Line 109, continue to operate at 20% pressure reduction (this restriction has been in place for 1462 days as of 12/17/2014). The pressure reduction for Lines 101, 132A, and 147 was in force for 368 days.[74] The pressure reduction for Lines 300A and 300B was in force for 294 days.[75] PHMSA lacks sufficient data or information to estimate and monetize the consequences of these operating restrictions. PG&E's system has crossties to enable continued gas supply to customers. Therefore, the impact of any reduction in capacity, if there was any, is difficult to estimate. However, the potential lost revenue and operational inefficiency resulting from the system operating restrictions could be significant.

This is conservative since PG&E costs incurred after December 31, 2013 are excluded. In its 2013 Annual Report, PG&E anticipated future unrecoverable costs associated with the San Bruno incident. These costs, $70 million of operator settlements to the City of San Bruno[76] (a transfer payment) and other unquantified costs were excluded from PHMSA's estimate of the total consequences of the San Bruno incident.

Table D-1 provides a summary of these estimates.

Table D-1. Summary of Consequences Associated with the 2010 San Bruno Pipeline Incident

Consequence	Value	Source
Deaths, injuries, and property damage	$565,000,000	PG&E Annual Reports
Cost of gas lost	$263,000	PG&E Incident Report
Emergency response (PG&E)	$250,000	NTSB Report, PHMSA estimate
Emergency response (public)	$50,000,000	NTSB Report, University of Delaware, PG&E Annual Reports
Disaster relief and evacuations	$64,987,210	PG&E Annual Reports, University of Delaware, American Red Cross
Mandatory pressure reduction	Not quantified	California Public Utilities Commission
Total	$680,500,210	See above

[74] California Public Utilities Commission, Press Release, December 15, 2011, http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/155625.htm
[75] California Public Utilities Commission, Press Release, October 6, 2011, http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/144858.htm
[76] *Ibid*., 50, pp. 14, 24

APPENDIX E CONSEQUENCES OF HISTORICAL INCIDENTS

Benefits for Topic Areas 1, 2, 3, 4, and 5 are based on preventing future incidents. In order to value the benefit of preventing future incidents, PHMSA used data from past incidents to estimate the “cost avoided” of preventing future incidents. PHMSA used data from incident reports submitted by operators for fatalities, injuries, other reported costs (which include operator property damage, other property damage, value of gas lost, and any other costs reported by the operator), and number of persons evacuated. PHMSA supplemented this data using publically available information (such as NTSB investigation reports) for selected incidents such as the San Bruno, California (see Appendix D) and Sissonville, West Virginia incidents.

For each topic area, PHMSA used a subset of the total incident filtered to only include incidents that could have reasonably be expected to have been avoided had the proposed rule requirements addressed by that topic area been in effect at the time. **Tables E-1** to **E-9** provide a summary for each subset of incident consequences used in this analysis. For comparison, Table E-1 provides incident data for gas transmission incidents for all causes is summarized in Table E-1. These tables exclude all reported operator property damage and repair costs (because they report these together) which results in understating incident costs since some of these costs (operator property damage, higher costs due to immediate need for the repair or replacement) would not be incurred with planned repair or replacement.

Regarding Table E-2, PHMSA incident data identifies the cause attributable to an incident. Some incidents might not be averted by integrity assessments and the management of time-dependent threats. Incidents due to hurricanes or other extreme weather events, or third-party damage incidents, where the pipe fails at the time of the damage would not necessarily be averted by the requirements in the proposed rule under Topic Area 1. Table E-3 summarizes the subset of gas transmission incidents that are attributable to the causes identified in Section 4.1. (Note that the list of causes was revised in 2010.) The data summarized in Table E-2 was reported to PHMSA in operator incident reports; except that publicly available information was used to estimate the consequences of the 2010 San Bruno incident (see Appendix D of this RIA).

Regarding Table E-4, note that there is no data that directly identifies whether historical incidents occurred in locations that would meet the definition of MCA under the proposed rule. PHMSA used the following two-phase approach to develop Table E-4 as a proxy for historical incidents with applicable cause codes associated with Topic Area 1 that would be located in an MCA:

1. PHMSA filtered the incidents that comprise Table E-2 to exclude HCAs and any incident that did not result in a death, reportable injury, or property damage (not owned by operator) under the premise that the lack of external consequences is likely indicative of few or no damage receptors within the PIR.
2. Of the incidents filtered out based on zero damage, PHMSA reviewed publicly available aerial photography and online mapping applications of the incident location. If it appeared as if the incident location was in proximity to five houses or a site that appeared as if it could be an occupied site, then PHMSA added those

incidents (34) to the subset of incidents that represent a proxy for MCA incidents.

Table E-1. Historical Consequences of Onshore Gas Transmission Incidents Due to All Causes (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuation[4]	Total Cost of Incidents	Average Cost per Incident
2003	81	1	$9,400,000	8	$7,896,000	$26,002,183	439	$658,500	$43,956,683	$542,675
2004	83	0	$0	2	$1,974,000	$4,027,541	1,036	$1,554,000	$7,555,541	$91,031
2005	106	0	$0	5	$4,935,000	$110,676,449	1,996	$2,994,000	$118,605,449	$1,118,919
2006	108	3	$28,200,000	3	$2,961,000	$8,419,432	995	$1,492,500	$41,072,932	$380,305
2007	86	2	$18,800,000	7	$6,909,000	$14,434,410	1,174	$1,761,000	$41,904,410	$487,261
2008	93	0	$0	5	$4,935,000	$12,154,890	635	$952,500	$18,042,390	$194,004
2009	92	0	$0	11	$10,857,000	$7,767,011	727	$1,090,500	$19,714,511	$214,288
2010	82	10	$94,000,000	61	$60,207,000	$418,615,646	265	$397,500	$573,220,146	$6,990,490
2011	101	0	$0	1	$987,000	$22,200,196	870	$1,305,000	$24,492,196	$242,497
2012	87	0	$0	7	$6,909,000	$13,710,727	904	$1,356,000	$21,975,727	$252,595
2013	93	0	$0	2	$1,974,000	$13,876,259	3,103	$4,654,500	$20,504,759	$220,481
2014	116	1	$9,400,000	1	$987,000	$14,867,441	1,445	$2,167,500	$27,421,941	$236,396
2015	117	6	$56,400,000	14	$13,818,000	$11,885,205	503	$754,500	$82,857,705	$708,186
Total	1,245	23	$216,200,000	127	$125,349,000	$678,637,389	14,092	$21,138,000	$1,041,324,389	$836,405

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-2. Historical Consequences of Onshore Gas Transmission Incidents due to Causes Detectable by Modern Integrity Assessment Methods[1] (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[2]	Number of Injuries	VSL Serious Injury[3]	Other Costs of Accident[4]	Number of Persons Evacuated	Estimated Cost of Evacuation[5]	Total Cost of Incidents	Average Cost per Incident
2003	33	0	$0	0	$0	$15,854,155	171	$256,500	$16,110,655	$488,202
2004	26	0	$0	0	$0	$1,108,283	229	$343,500	$1,451,783	$55,838
2005	27	0	$0	0	$0	$105,697,938	384	$576,000	$106,273,938	$3,936,072
2006	44	0	$0	0	$0	$2,802,314	52	$78,000	$2,880,314	$65,462
2007	38	1	$9,400,000	3	$2,961,000	$11,941,122	263	$394,500	$21,735,622	$571,990
2008	30	0	$0	1	$987,000	$8,200,877	331	$496,500	$8,697,377	$289,913
2009	32	0	$0	3	$2,961,000	$2,494,681	278	$417,000	$2,911,681	$90,990
2010	28	8	$75,200,000	51	$50,337,000	$412,056,506	29	$43,500	$487,300,006	$17,403,572
2011	29	0	$0	0	$0	$8,020,221	66	$99,000	$8,119,221	$279,973
2012	26	0	$0	0	$0	$7,585,658	524	$786,000	$8,371,658	$321,987
2013	27	0	$0	2	$1,974,000	$8,124,268	451	$676,500	$8,800,768	$325,954
2014	31	0	$0	0	$0	$5,359,479	598	$897,000	$6,256,479	$201,822
2015	28	0	$0	0	$0	$3,961,837	366	$549,000	$4,510,837	$161,101
Total	399	9	$84,600,000	60	$59,220,000	$593,207,339	3,742	$5,613,000	$683,420,339	$1,712,833

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Inline inspection, pressure testing, direct assessment, and other technology.
2. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
3. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
4. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
5. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-3. Historical Consequences of Gas Transmission Incidents due to Causes Detectable by Modern Integrity Assessment Methods[1] Located in HCAs (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[2]	Number of Injuries	VSL Serious Injury[3]	Other Costs of Accident[4]	Number of Persons Evacuated	Estimated Cost of Evacuation[5]	Total Cost of Incidents	Average Cost per Incident
2003	2	0	$0	0	$0	$3,065,772	0	$0	$3,065,772	$1,532,886
2004	3	0	$0	0	$0	$90,612	28	$42,000	$132,612	$44,204
2005	1	0	$0	0	$0	$1,056	0	$0	$1,056	$1,056
2006	2	0	$0	0	$0	$20,187	0	$0	$20,187	$10,094
2007	2	0	$0	0	$0	$267,564	200	$300,000	$567,564	$283,782
2008	1	0	$0	0	$0	$15,577	30	$45,000	$60,577	$60,577
2009	0	0	$0	0	$0	$0	0	$0	$0	$0
2010	2	8	$75,200,000	51	$50,337,000	$407,516,568	0	$0	$533,053,568	$266,526,784
2011	2	0	$0	0	$0	$302,089	0	$0	$302,089	$151,044
2012	3	0	$0	0	$0	$280,668	500	$750,000	$1,030,668	$343,556
2013	0	0	$0	0	$0	$0	0	$0	$0	$0
2014	4	0	$0	0	$0	$141,019	18	$27,000	$168,019	$42,005
2015	1	0	$0	0	$0	$58	0	$0	$58	$58
Total	23	8	$75,200,000	51	$50,337,000	$411,701,171	776	$1,164,000	$538,402,171	$23,408,790

HCA = high consequence area
VSL = value of statistical life
Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files
1. Inline inspection, pressure testing, direct assessment, and other technology.
2. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
3. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
4. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
5. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-4. Historical Consequences of Gas Transmission Incidents due to Causes Detectable by Modern Integrity Assessment Methods[1] Located in Proposed MCA (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[2]	Number of Injuries	VSL Serious Injury[3]	Other Costs of Accident[4]	Number of Persons Evacuated	Estimated Cost of Evacuation[5]	Total Cost of Incidents	Average Cost per Incident
2003	11	0	$0	0	$0	$12,977,374	13	$19,500	$12,996,874	$1,181,534
2004	7	0	$0	0	$0	$216,205	0	$0	$216,205	$30,886
2005	5	0	$0	0	$0	$102,653,637	240	$360,000	$103,013,637	$20,602,727
2006	14	0	$0	0	$0	$926,494	33	$49,500	$975,994	$69,714
2007	16	1	$9,400,000	3	$2,961,000	$8,312,698	63	$94,500	$20,768,198	$1,298,012
2008	13	0	$0	0	$0	$6,913,847	298	$447,000	$7,360,847	$566,219
2009	9	0	$0	3	$2,961,000	$873,649	207	$310,500	$4,145,149	$460,572
2010	10	0	$0	0	$0	$2,651,682	0	$0	$2,651,682	$265,168
2011	11	0	$0	0	$0	$16,123,614	35	$52,500	$16,176,114	$1,470,556
2012	11	0	$0	0	$0	$3,334,972	22	$33,000	$3,367,972	$306,179
2013	12	0	$0	2	$1,974,000	$8,702,995	451	$676,500	$11,353,495	$946,125
2014	27	0	$0	0	$0	$2,534,887	27	$40,500	$2,575,387	$95,384.70
2015	27	0	$0	0	$0	$2,177,212	27	$40,500	$2,217,712	$82,137
Total	173	1	$9,400,000	8	$7,896,000	$168,399,264	1416	$2,124,000	$187,819,264	$1,085,660

MCA = moderate consequence area (five building in the potential impact radius criterion)
VSL = value of statistical life
Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files
1. Inline inspection, pressure testing, direct assessment, and other technology.
2. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
3. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
4. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
5. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-5. Historical Consequences of Gas Transmission Incidents due to Corrosion (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuation[4]	Total Cost of Incidents	Average Cost per Incident
2003	21	1	$9,400,000	1	$987,000	$10,202,074	171	$256,500	$20,845,574	$992,646
2004	26	0	$0	1	$987,000	$1,171,118	262	$393,000	$2,551,118	$98,120
2005	26	0	$0	1	$987,000	$1,958,592	44	$66,000	$3,011,592	$115,830
2006	32	3	$28,200,000	0	$0	$2,458,396	33	$49,500	$30,707,896	$959,622
2007	34	2	$18,800,000	3	$2,961,000	$5,538,624	138	$207,000	$27,506,624	$809,018
2008	25	0	$0	1	$987,000	$7,808,619	295	$442,500	$9,238,119	$369,525
2009	17	0	$0	0	$0	$1,246,324	83	$124,500	$1,370,824	$80,637
2010	24	2	$18,800,000	7	$6,909,000	$5,372,531	6	$9,000	$31,090,531	$1,295,439
2011	24	0	$0	0	$0	$3,935,920	65	$97,500	$4,033,420	$168,059
2012	20	0	$0	2	$1,974,000	$6,509,273	12	$18,000	$8,501,273	$425,064
2013	25	0	$0	2	$1,974,000	$4,820,896	2567	$3,850,500	$10,645,396	$425,816
2014	22	0	$0	0	$0	$2,216,570	15	$22,500	$2,239,070	$101,776
2015	24	1	$9,400,000	2	$1,974,000	$2,904,165	46	$69,000	$14,347,165	$597,799
Total	320	9	$84,600,000	20	$19,740,000	$56,143,103	3737	$5,605,500	$166,088,603	$519,027

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-6. Historical Consequences of Gas Transmission Incidents due to External Natural Force Damage Events (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuation[4]	Total Cost of Incidents	Average Cost per Incident
2003	3	0	$0	0	$0	$124,874	0	$0	$124,874	$41,625
2004	5	0	$0	0	$0	$240,779	0	$0	$240,779	$48,156
2005	22	0	$0	0	$0	$1,151,038	0	$0	$1,151,038	$52,320
2006	4	0	$0	0	$0	$108,107	10	$15,000	$123,107	$30,777
2007	6	0	$0	0	$0	$236,541	206	$309,000	$545,541	$90,924
2008	12	0	$0	0	$0	$695,379	0	$0	$695,379	$57,948
2009	9	0	$0	0	$0	$605,516	138	$207,000	$812,516	$90,280
2010	6	0	$0	0	$0	$340,174	0	$0	$340,174	$56,696
2011	16	0	$0	0	$0	$3,566,551	141	$211,500	$3,778,051	$236,128
2012	5	0	$0	0	$0	$1,129,508	30	$45,000	$1,174,508	$234,902
2013	7	0	$0	0	$0	$279,537	0	$0	$279,537	$39,934
2014	13	0	$0	0	$0	$3,026,390	510	$765,000	$3,791,390	$291,645
2015	10	0	$0	0	$0	$404,247	0	$0	$404,247	$40,424.70
Total	118	0	$0	0	$0	$11,908,640	1035	$1,552,500	$13,461,140	$114,077

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-7. Historical Consequences of Gas Transmission Incidents due to Pipe Failure due to Corrosion and Excavation Damage in Class 1 and Class 2 Locations. (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuation[4]	Total Cost of Incidents	Average Cost per Incident
2003	21	1	$9,400,000	1	$987,000	$10,202,074	171	$256,500	$20,845,574	$992,646
2004	26	0	$0	1	$987,000	$1,171,118	262	$393,000	$2,551,118	$98,120
2005	26	0	$0	1	$987,000	$1,958,592	44	$66,000	$3,011,592	$115,830
2006	32	3	$28,200,000	0	$0	$2,458,396	33	$49,500	$30,707,896	$959,622
2007	34	2	$18,800,000	3	$2,961,000	$5,538,624	138	$207,000	$27,506,624	$809,018
2008	25	0	$0	1	$987,000	$7,808,619	295	$442,500	$9,238,119	$369,525
2009	17	0	$0	0	$0	$1,246,324	83	$124,500	$1,370,824	$80,637
2010	24	2	$18,800,000	7	$6,909,000	$5,372,531	6	$9,000	$31,090,531	$1,295,439
2011	24	0	$0	0	$0	$3,935,920	65	$97,500	$4,033,420	$168,059
2012	20	0	$0	2	$1,974,000	$6,509,273	12	$18,000	$8,501,273	$425,064
2013	25	0	$0	2	$1,974,000	$4,820,896	2567	$3,850,500	$10,645,396	$425,816
2014	22	0	$0	0	$0	$2,216,570	15	$22,500	$2,239,070	$101,776
2015	24	1	$9,400,000	2	$1,974,000	$2,904,165	46	$69,000	$14,347,165	$597,799
Total	320	9	$84,600,000	20	$19,740,000	$56,143,103	3737	$5,605,500	$166,088,603	$519,027

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-8. Historical Consequences of Gas Transmission Incidents due to Causes Detectible by Modern Integrity Management Methods[1] Located in Non-HCA Class 3 and Class 4 (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuation[4]	Total Cost of Incidents	Average Cost per Incident
2003	0	0	$0	0	$0	$0	0	$0	$0	$0
2004	2	0	$0	0	$0	$13,506	1	$1,500	$15,006	$7,503
2005	3	0	$0	0	$0	$40,964	100	$150,000	$190,964	$63,655
2006	2	0	$0	0	$0	$93,107	0	$0	$93,107	$46,553
2007	1	0	$0	0	$0	$48	0	$0	$48	$48
2008	3	0	$0	0	$0	$6,409	2	$3,000	$9,409	$3,136
2009	3	0	$0	0	$0	$147,752	99	$148,500	$296,252	$98,751
2010	1	0	$0	0	$0	$8,907	0	$0	$8,907	$8,907
2011	0	0	$0	0	$0	$0	0	$0	$0	$0
2012	2	0	$0	0	$0	$4,188	0	$0	$4,188	$2,094
2013	1	0	$0	0	$0	$1,540,149	175	$262,500	$1,802,649	$1,802,649
2014	2	0	$0	0	$0	$652,110	20	$30,000	$682,110	$341,055
2015	1	0	$0	0	$0	$1,152	0	$0	$1,152	$1,152
Total	21	0	$0	0	$0	$2,508,292	397	$595,500	$3,103,792	$147,800

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-9. Historical Consequences of Gas Transmission Incidents due to Causes Detectible by Modern Integrity Management Methods (ILI, Pressure Testing, Direct Assessment, Other Technology) Located Alternate 1 Structure PIR MCA (2003-2013; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuation[4]	Total Cost of Incidents	Average Cost per Incident
2003	26	0	$0	0	$0	$13,155,941	13	$19,500	$13,175,441	$506,748
2004	17	0	$0	0	$0	$219,159	0	$0	$219,159	$12,892
2005	23	0	$0	0	$0	$103,043,595	280	$420,000	$103,463,595	$4,498,417
2006	27	0	$0	0	$0	$1,063,038	42	$63,000	$1,126,038	$41,705
2007	28	1	$9,400,000	3	$2,961,000	$8,478,907	263	$394,500	$21,234,407	$758,372
2008	18	0	$0	0	$0	$6,921,409	300	$450,000	$7,371,409	$409,523
2009	24	0	$0	3	$2,961,000	$923,407	207	$310,500	$4,194,907	$174,788
2010	25	0	$0	0	$0	$3,359,001	0	$0	$3,359,001	$134,360
2011	25	0	$0	0	$0	$16,123,614	35	$52,500	$16,176,114	$647,045
2012	23	0	$0	0	$0	$4,506,211	24	$36,000	$4,542,211	$197,487
2013	26	0	$0	2	$1,974,000	$8,702,995	451	$676,500	$11,353,495	$436,673
2014	10	0	$0	2	$1,974,000	$11,240,623	10	$15,000	$13,229,623	$1,322,962
2015	6	0	$0	2	$1,974,000	$3,732,419	6	$9,000	$5,715,419	$952,570
Total	278	1	$9,400,000	12	$11,844,000	$181,470,320	1631	$2,446,500	$205,160,820	$737,989

VSL = value of statistical life
Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files
1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).