Preliminary Regulatory Impact Analysis

Regulatory Development Support Services
Pipeline Safety: Safety of Hazardous Liquid Pipelines Notice of Proposed Rulemaking (NPRM)

Contract No.:
DPTH56-09-F-000012

Order No.:
DTPH56-09-F-000012TTD002

Project No.:
1027-002

Submitted To:

Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
Attn.: Cheryl Whetsel, COR
1200 New Jersey Avenue, SE
Washington, DC 20590-0001

Submitted By:

Econometrica, Inc.
7475 Wisconsin Avenue, Suite 1000
Bethesda, MD 20814

October 1, 2015

ECONOMETRICA, INC.

Table of Contents

Executive Summary

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is proposing to make certain changes to the hazardous liquid (HL) pipeline safety regulations.[1] The proposed changes include the following: (1) extend reporting requirements to gravity lines; (2) extend certain reporting requirements to HL gathering lines located outside of high consequence areas (HCAs);[2] (3) require inspections of pipelines in areas affected by extreme weather, natural disasters, and other similar events within 72 hours and appropriate remedial action to ensure the safe operation of a pipeline; (4) require assessments of pipelines located in non-HCAs every 10 years using in-line inspection (ILI) tools; (5) expand the use of leak detection systems (LDSs) to HL pipelines located in non-HCAs to mitigate the effects of failures that occur outside of HCAs; (6) modify the Integrity Management (IM) repair criteria and apply those same criteria to pipelines that are not subject to the IM requirements; (7) increase the use of ILI tools by requiring that any pipeline that could affect an HCA be capable of accommodating these devices within 20 years, unless its basic construction will not permit that accommodation; and (8) resolve inconsistent deadlines, clarify requirements for information integration, clarify definition of covered pipeline facilities, and specify timeframe for rechecking HCA status for the IM Plan.

Different requirements in this Notice of Proposed Rulemaking (NPRM) affect different sets of operators, and different mileage segments are also affected by different parts of the proposal. Some of the requirements are directed only to pipelines in HCAs, and others are directed only to pipelines outside of HCAs. Some requirements incorporate only onshore pipelines, and others refer to offshore also. Throughout the analysis, the cost estimates are based on assumptions regarding how operators will choose to comply with many of the proposed requirements. The resulting cost estimates are based on information available at the time of the analysis. Similarly, the benefits of the requirements will be affected by how effective the rule will be in reducing or mitigating the costs associated with incidents. Some of the requirements provide a period of time before operators must comply and the timing of when mandatory compliance will affect both the cost and benefit estimates.

In this regulatory analysis, we discuss PHMSA's alternatives to the proposed requirements and, where possible, provide estimates of the costs and benefits for specific regulatory requirements in the eight areas. The regulatory analysis provides PHMSA's best estimate of the impact of the separate proposed requirements and throughout invites comment on the assumptions and methodologies employed. For some of the provisions, the costs and benefits are not readily

[1] PHMSA, U.S. Department of Transportation (DOT), 49CFR Part 195. Docket No. PHMSA-2010-0229 RIN 2137-AE66. The proposed action is in response to the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (P.L. 112-90), National Transportation Safety Board (NTSB) recommendations to update HL pipeline regulations, lessons learned, and public input.

[2] For HL pipelines, HCAs include populated areas, drinking water sources, and unusually sensitive ecological areas. FR §195.452 requires HL pipeline operators to conduct an initial risk assessment to determine if an accidental release from any segment of their pipeline could reach an HCA. Operators are required to meet more stringent regulatory requirements known as IM for segments of their pipeline from which a release could reach an HCA. Any pipeline from which a release "could affect" an HCA is subject to the IM Rule. In this document, we use HCA and "could affect HCA" interchangeably. For more information, please see PHMSA's "Fact Sheet: High Consequence Areas" at http://primis.phmsa.dot.gov/comm/FactSheets/FSHCA.htm. Accessed December 15, 2014.

quantified or possible to monetize. Estimates of the annual costs and potential benefits that are quantified are discounted at both 3 percent and 7 percent and presented in the analysis of the requirements to arrive at the present values for purposes of comparison. The present values of costs and potential benefits are calculated over different time periods, depending on the nature of the requirements. Table ES-1 presents a summary of the present value of the annualized costs and benefits for the eight requirement areas in the proposed rule discounted at 7 percent.

Table ES-1. Annualized Costs and Benefits by Requirement Area Discounted at 7 Percent

Requirement Area	Costs	Benefits	Net Benefits
1. Extend certain reporting requirements to all HL gravity lines.	$900	Benefits not quantified but expected to justify costs.	Expected to be positive.
2. Extend certain reporting requirements to all HL gathering lines.	$23,300	Benefits not quantified but expected to justify the costs.	Expected to be positive.
3. Require inspections of pipelines in areas affected by extreme weather, natural disasters, and other similar events, as well as appropriate remedial action if a condition that could adversely affect the safe operation of a pipeline is discovered.	$1.5 million	$3.5 to 10.4 million	$2.0 to 8.9 million
4. Require periodic assessments of pipelines that are not already covered under the IM program requirements using an ILI tool (or demonstrate to the satisfaction of PHMSA that the pipeline is not capable of using this tool).	$16.7 million	$17.7 million Range: $9.4 to $26.0 million	$1 million Range: -$7.3 to $9.3 million Expected to be positive even at the low end of the benefit range if unquantified benefits are included.
5. Require use of LDSs on HL pipelines located in non-HCAs to mitigate the effects of failures that occur outside of HCAs.	Not quantified. PHMSA assumes that the cost of expanding LDSs to existing and newly built pipelines in non-HCAs and performing any additional repairs to realize benefits would be minimal.	Not quantified but expected to be minimal and justify the costs.	Not quantified, but positive qualitative benefits.

Requirement Area	Costs	Benefits	Net Benefits
6. Modify the IM repair criteria, both by expanding the list of conditions that require immediate remediation, consolidating the timeframes for remediating all other conditions, and making explicit deadlines for repairs on non-IM pipeline.	Not quantified but expected to be minimal.	Not quantified but expected to justify the minimal costs.	Not quantified but expected to be minimal.
7. Increase the use of ILI tools by requiring that any pipeline that could affect an HCA be capable of accommodating these devices within 20 years, unless its basic construction will not permit that accommodation.	$1.0 million	$12.2 million	$11.2 million
8. Clarify and resolve inconsistencies regarding deadlines and information analyses for IM plans.	$3.2 million	$10.0 million	$6.8 million

The proposed rule is a significant regulatory action under DOT's regulatory policies and procedures (44 FR 11034; February 26, 1979) but is not economically significant under EO 12866 and EO 13563 because the estimated annual impact is less than $100 million.

Looking at the individual provisions of the proposed rule, the quantified benefits justify the costs except for in the case of Requirement 4. Factors such as an increase in public confidence that all pipelines are being regulated and better risk management procedures on the part of operators are expected to yield qualitative and quantitative benefits that are in further excess of the costs.

Section 202 of the Unfunded Mandates Reform Act of 1995 requires that agencies assess anticipated costs and benefits before issuing any rule whose mandates would require spending $151 million in any one year. This proposed rule does not impose enforceable duties on State, local, or tribal governments or on the private sector of $155 million in any one year.

1. Introduction

1.1. Background

PHMSA (or "the Agency") is the agency within DOT (or "the Department") that administers the Pipeline Safety Laws. On October 18, 2010 (75 FR 63774), PHMSA published an ANPRM asking the public to comment on several proposed changes to Part 195.[3] The ANPRM sought comments on the following:

1. Scope of Part 195 and Existing Regulatory Exceptions.
2. Criteria for Designation of HCAs.
3. Leak Detection and Emergency Flow Restricting Devices.
4. Valve Spacing.
5. Repair Criteria Outside of HCAs.
6. Stress Corrosion Cracking.

Twenty-one organizations and individuals submitted comments in response to the ANPRM. The analysis of comments appears in "Notice of Proposed Rulemaking Safety of Onshore HL Pipelines Docket Number PHMSA 2010-0229."

1.2. Notice of Proposed Rulemaking

In response to mandates, recommendations, lessons learned, and public input, PHMSA is proposing to make certain changes to the Hazardous Liquid Pipeline Safety Regulations.

- The first proposal is to extend reporting requirements to gravity lines. Other pipelines that operate at relatively low pressures (such as gathering lines), and for short distances, are subject to reporting requirements. Gravity lines can operate at pressures that exceed low pressure pipelines or gathering lines due to significant elevation differences needed to provide the motive force for liquid flow and thus can represent as much or more risk than low pressure lines or gathering lines. The collection of information about these lines is authorized under the Pipeline Safety Laws, and the resulting data would assist in determining whether the existing Federal and State regulations for these lines are adequate.
- The second proposal is to extend reporting requirements to all HL gathering lines. The collection of information about these lines is also authorized under the Pipeline Safety Laws, and the resulting data would assist in determining whether the existing Federal and State regulations for these lines are adequate.
- The third proposal is to require inspections within 72 hours of pipelines in areas affected by extreme weather, natural disasters, and other similar events. Such inspections would ensure that pipelines are still capable of being safely operated after these events. PHMSA is also proposing to require operators to take remedial action if a condition that could adversely affect the safe operation of a pipeline is discovered.

[3] The ANPRM may be viewed at http://www.regulations.gov/#!docketDetail;D=PHMSA-2010-0229 (accessed August 15, 2012).

- The fourth proposal is to require assessments of HL pipelines that are located outside of HCAs using ILI tools at least once every 10 years. Pipelines that could affect HCAs are already required under the IM program requirements to be assessed using ILI, hydrostatic testing, or direct assessment. This proposed requirement would provide critical information about the condition of pipelines located in non-HCAs, including the existence of internal and external corrosion and deformation anomalies.
- The fifth proposal is to require the use of LDSs on HL pipelines located in non-HCAs. LDSs are already required for segments of pipeline that could reach an HCA. The use of such systems would help mitigate the effects of HL pipeline failures that occur outside of HCAs.
- The sixth proposal is to modify the provisions for making pipeline repairs. Additional conservatism would be incorporated into the existing repair criteria and an adjusted schedule will be established to provide greater uniformity. These criteria would also be made applicable to all HL pipelines, with an extended timeframe for making repairs outside of HCAs.
- The seventh proposal is to require that all pipelines subject to the IM requirements be capable of accommodating ILI tools within 20 years, unless the basic construction of a pipeline cannot be modified to permit that accommodation. ILI tools are an effective means of assessing the integrity of a pipeline. Broadening their use would improve the detection of anomalies and prevent or mitigate future accidents in high-risk areas.
- Finally, PHMSA is proposing clarification changes to other regulations to improve certainty and compliance.

1.3. Effectiveness of the Rule

PHMSA expects that the proposed changes will protect the public, property, and the environment by increasing the detection and remediation of unsafe conditions and mitigating the adverse effects of pipeline failures.

In the past 10 years, PHMSA has issued the following final rules that affect HL pipelines.

A. Protecting Unusually Sensitive Areas From Rural Onshore Hazardous Liquid Gathering Lines and Low-Stress Lines, June 3, 2008 (Docket No. PHMSA-2003-15864)
Operators of rural gathering lines meeting certain criteria must comply with pipeline safety requirements that address corrosion and third-party damage. In particular, operators of these lines must establish maximum operating pressure, install and maintain line markers, establish continuing public education and damage prevention programs, comply with corrosion control requirements, implement programs for continuously identifying operating conditions that could contribute to internal corrosion (including measures to prevent and mitigate internal corrosion), and comply with operator qualification programs. In addition, operators of regulated rural gathering lines must comply with Subpart B's reporting requirements.

The regulations require that larger-diameter rural low-stress pipelines comply with all Part 195 safety requirements and shutdown ability, to determine if a pipeline could affect an unusually sensitive area (USA). New steel gathering lines constructed, replaced, relocated, or otherwise changed after July 3, 2009, must comply with Part 195's installation, construction, initial inspection, and initial testing requirements. For pipelines that become regulated because of the identification of a new USA, an operator must implement the regulatory requirements (except for Subpart H corrosion control requirements) within 6 months of identifying the USA for gathering lines and within 12 months of identifying low-stress pipelines.

B. Pipeline Safety: Control Room Management/Human Factors, February 3, 2010

PHMSA amended the Federal pipeline safety regulations to address human factors and other aspects of control room management for pipelines where controllers use supervisory control and data acquisition (SCADA) systems. Under the final rule, affected pipeline operators must define the roles and responsibilities of controllers and provide controllers with the necessary information, training, and processes to fulfill these responsibilities. Operators must also implement methods to prevent controller fatigue. The final rule further requires operators to manage SCADA alarms, ensure that control room considerations are taken into account when changing pipeline equipment or configurations, and review reportable incidents or accidents to determine whether control room actions contributed to the event.

HL and gas pipelines are often monitored in a control room by controllers using computer-based equipment, such as a SCADA system, that records and displays operational information about the pipeline system, such as pressures, flow rates, and valve positions. Some SCADA systems are used by controllers to operate pipeline equipment, while in other cases, controllers may dispatch other personnel to operate equipment in the field. These monitoring and control actions, whether via SCADA system commands or direction to field personnel, are a principal means of managing pipeline operation.

This rule improves opportunities to reduce risk through more effective control of pipelines. It further requires the statutorily mandated human factors management. These regulations will enhance pipeline safety by coupling strengthened control room management with improved controller training and fatigue management.

C. Application of Safety Regulation to Rural Onshore Hazardous Liquid Low-Stress Pipelines (Phase II), May 5, 2011

PHMSA amended its pipeline safety regulations to apply safety regulation to rural low-stress HL pipelines that were not covered previously by safety regulations. This change complies with a mandate in the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES Act).

Some rules may overlap and thus would not result in mutually exclusive benefits. PHMSA estimates that the group of previously published rules has resulted in some reduction in incidents, most of which is accounted for in the data presented in the area requirement analyses. PHMSA sees the following regulatory effects, which affect the benefits and the effectiveness of the rule:

Area	Effect
1. Extend reporting requirements to all HL gravity lines.	Provides information to improve the effectiveness of regulatory policies.
2. Extend reporting requirements to all HL gathering lines.	Provides information to improve the effectiveness of regulatory policies.
3. Require inspections of pipelines in areas affected by extreme weather, natural disasters, and other similar events.	PHMSA believes that most operators already perform these inspections. To the extent operators do not currently perform them within 72 hours following an event, this proposal lowers the likelihood of an accident.
4. Require assessments for corrosion and deformation anomalies of HL pipelines that are located outside of HCAs at least once every 10 years.	Lowers the likelihood of an accident.
5. Require the use of LDSs on HL pipelines located in non-HCA.	Minimal because most all operators already use LDSs on their non-HCA pipe. For the very few that do not, this proposal would mitigate the effects of an accident by lowering the quantity of product spilled.
6. Modify the provisions for making pipeline repairs.	Mitigates the effects of an accident by lowering the quantity of product spilled.
7. Require that all pipelines subject to the IM requirements be capable of accommodating ILI tools within 20 years, unless the basic construction of a pipeline cannot be modified to permit that accommodation.	Mitigates the effects of an accident by lowering the quantity of product spilled.
8. Clarify regulations.	Improves compliance.

PHMSA believes that the effectiveness of the rule would range from 10 percent to 50 percent, depending on the proposed requirement. The effectiveness will be addressed separately in the individual analysis. The risks addressed by each of the different proposed requirements may not all be mutually exclusive, but that does not necessarily lead to assigning benefits more than once. For example, although three of the requirements—inspections following natural events, clarifications, and repair criteria modification—might apply to all pipelines, they would not apply to gravity lines or operators who are not required to report without those separate requirements. In addition, when operators are not required to report because of exemptions, exceptions, or exclusions, the total extent of incidents and associated societal costs and potential benefits cannot be known.

1.4. HL Pipeline Segments and Operators Potentially Affected

In general, it is difficult to estimate pipeline mileage for each requirement in this NPRM. The pipeline segments impacted depend on many factors such as the location of the pipeline (inside HCAs or outside HCAs); the product transported (in this case a petroleum or a petroleum product); the length, diameter, and type of pipeline; and the reconfiguration of pipelines that occurs following changes made to the pipeline by either installing new pipelines or abandoning old pipelines.

Based on PHMSA and publicly available data, we estimated that currently, there are 421 HL pipeline operators.[4] Two hundred and twenty of the operators have pipelines less than 50 miles long, 96 operators have pipelines between 50 and 250 miles long, and 105 operators have pipelines greater than 250 miles in length.[5] Table 1 describes the entities and the pipelines affected by this NPRM.

Table 1. Estimated Entities and Pipeline Segments Affected by the NPRM by Proposed Requirement Area

Proposed Requirement Area	Entities Affected	Pipeline Segments Affected		
	Estimate of Possible Number of Operators[6]	Estimate of Possible Total Number of Pipeline Miles Affected by the Proposed Rule[7]	Onshore	Offshore
1. Extend reporting requirements to HCA and non-HCA HL gravity lines.	3 to 5[8]	17[9] to 28[10]	✓	
2. Extend reporting requirements to HL gathering lines located in non-HCAs.	23[11]	26,000 to 36,000[12]	✓	
3. Require inspections of pipelines in areas affected by extreme weather, natural disasters, and other similar events, and remedial action.	421	191,478	✓	✓

[4] See https://www.federalregister.gov/articles/2010/01/26/2010-1497/pipeline-safety-leak-detection-on-hazardous-liquid-pipelines#h-6 (accessed August 9, 2014).
[5] Derived from PHMSA Annual Report data, available at http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print (accessed January 2, 2015).
[6] Most estimates are based on available PHMSA data. Source of estimates not from PHMSA data are included in the footnotes to the table. PHMSA data used for this table is available at http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print (accessed January 2, 2015).
[7] Most estimates are based on available PHMSA data. Source of estimates not from PHMSA data are included in the footnotes to the table.
[8] Estimate based on data provided by the PHMSA Data Manager. One known gravity line is the TESORO pipeline, which runs to a refinery near Kenai, AK.
[9] American Petroleum Institute and Association of Oil Pipelines Comment in response to ANPRM, Docket PHMSA-2010-0229. The estimate is based on the 2009 Pipeline Performance Tracking System, a survey of HL pipeline operators. Respondents reported on approximately 150,000 of total pipeline miles.
[10] Estimate based on data provided by the PHMSA Data Manager.
[11] American Petroleum Institute and Association of Oil Pipelines Comment in response to ANPRM, Docket PHMSA-2010-0229. The estimate is based on the 2009 Pipeline Performance Tracking System, a survey of HL pipeline operators. Respondents reported on approximately 150,000 of total pipeline miles.
[12] See NPRM, page 18, response to comments on "Rural Gathering Lines." The Association of Oil Pipelines (AOPL) in its comments (see footnote 3 for source) notes that it estimates that there are 6,705 miles impacted; however, PHMSA in the NPRM notes that "PHMSA only regulates 3,644 miles of the approximately 30,000 to 40,000 miles of onshore hazardous liquid gathering lines in the United States." By PHMSA estimates, this leaves approximately 26,000 to 36,000 miles of HL gathering lines unregulated.

Proposed Requirement Area	Entities Affected	Pipeline Segments Affected		
	Estimate of Possible Number of Operators[6]	Estimate of Possible Total Number of Pipeline Miles Affected by the Proposed Rule[7]	Onshore	Offshore
4. Require assessments of non-HCA pipeline using ILI tools every 10 years.	421	17,794	✓	✓
5. Require LDSs on HL pipelines located outside of HCAs to mitigate the effects of failures that occur.	421	2,565	✓	✓
6. Modify the IM repair criteria, both by expanding the list of conditions that require immediate remediation and consolidating the timeframes for remediating all other conditions, and apply those same criteria to pipelines that are not subject to the IM requirements.	421	191,478	✓	✓
7. Increase the use of ILI tools by requiring that pipelines in areas that could affect an HCA be capable of accommodating these devices within 20 years, unless its basic construction will not permit that accommodation.	All operators with pipelines that could affect HCAs	83,014	✓	✓
8. Clarify other regulations to improve compliance and enforcement.	421	191,478	✓	✓

1.5. Factors That May Affect the Costs and Benefits

Estimates of impacts, costs, and benefits are calculated based on the action taken for each requirement area. Regarding compliance cost, there is no specific general rule that can cover all situations. The costs will depend on factors such as where the pipeline is located, how much of the pipeline is affected, the type of pipeline, the size of the pipeline, and the method used to address the requirements. For example:

- ILI tools are not 100 percent effective and may not detect all defects (proposed requirement area number 4).[13] Also, the results of inspections may not be accurately assessed. For example, even after Enbridge inspected a 34-inch pipeline near Cohasset, MN, with the Elastic Wave ILI, the pipeline ruptured. NTSB determined that the probable cause of the July 4, 2002, incident “was inadequate loading of the pipe for transportation that allowed a fatigue crack to initiate along the seam of the longitudinal weld during transit. After the pipe was installed, the fatigue crack grew with pressure

[13] For more information about smart pig technology, see presentations from the June 24, 2011, ILI symposium hosted by the California Public Utilities Commission. http://www.cpuc.ca.gov/NR/rdonlyres/0DEA7BA4-5421-4287-BD32-A22863A2BFE9/0/INLINEINSPECTIONSYMPOSIUMCONCATENATEDFINAL.pdf (accessed January 7, 2015.)

cycle stresses until the crack reached a critical size and the pipe ruptured. The Elastic Wave ILI conducted before the accident recorded an indication at the point where the pipe eventually failed; however, pre-accident and post-accident interpretations of the recorded data found that the indication did not meet the feature selection criteria to identify it as a crack."[14]

- Regarding the requirement associated with the LDS (proposed requirement area number 5), there is no one system that would effectively detect all HL pipeline leaks, and few systems can be programmed to detect small leaks without generating false positives or false negatives. In general, the type of LDS selected depends on a variety of factors, including pipeline characteristics, product characteristics, instrumentation, communications capabilities, and economic factors.

[14] See http://www.ntsb.gov/doclib/reports/2004/PAR0401.pdf (accessed August 12, 2014), page 33.

2. Regulatory Analysis

2.1. Introduction

Executive Order 12866, "Regulatory Planning and Review," directs all Federal agencies to develop both preliminary and final regulatory analyses if their regulations are likely to be "significant regulatory actions" that may have an annual impact on the economy of $100 million or more.

The more recent Executive Order 13563, "Improving Regulation and Regulatory Review," January 18, 2011, emphasizes careful consideration of costs and benefits and directs agencies to use the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible and to proceed only if the benefits justify the costs.

In accordance with the guidance provided by the Office of Management and Budget's (OMB's) Circular A-4 on the development of regulatory analysis as required under Section 6(a)(3)(c) of Executive Order 12866, the Regulatory Right-to-Know Act, and a variety of related authorities, this regulatory analysis addresses the following:

- Describes the need for the regulatory action.
- Defines the baseline.
- Sets the timeframe of analysis.
- Identifies a range of regulatory alternatives.
- Identifies the consequences of regulatory alternatives.
- Quantifies and monetizes the benefits and costs or evaluates non-quantified costs and benefits.
- Discounts future benefits and costs.

The proposed rule contains eight separate regulatory initiatives. Therefore, we chose to discuss the overall implications in this chapter (following the OMB guidelines) and present the individual (requirement area by requirement area) regulatory impact analysis (RIA) in subsequent chapters. The remainder of this chapter presents an **overview** of the factors considered for the analysis in accordance with OMB guidelines.

2.2. Need for the Regulatory Action

The need for PHMSA's actions is based on three external and internal components—Economic, Legislative, and Strategic Objectives.

2.2.1. Economic – Market Failure

HL pipelines, in most instances, meet the definition of a natural monopoly. A natural monopoly is a distinct type of monopoly that may arise when there are extremely high fixed costs of production and very long-term average costs in an industry. Such a situation exists when large-scale infrastructure is required to ensure supply of the good. Common examples of natural monopolies include railroad, electricity grids, oil pipelines, and water supply.[15] As such, HL pipelines are regulated by the Federal Energy Regulatory Commission (FERC). FERC's oversight includes regulation of rates and practices of oil pipeline companies engaged in interstate transportation, establishment of equal service conditions to provide shippers with equal access to pipeline transportation, and establishment of reasonable rates for transporting petroleum and petroleum products by pipeline. PHMSA oversees the development and implementation of regulations concerning pipeline construction, maintenance, and operation, in cooperation with State regulatory partners.

In addition, health, safety, and environmental-related regulations associated with HL pipelines exist under the IM program and other requirements. This proposal is expected to enhance the IM program and increases the coverage to other operators or pipelines for which there has been an exception or they were otherwise exempt from IM program coverage. Aside from the reporting requirement extensions to gathering lines and gravity lines, all of the other requirements are aimed at HL spills—either preventing them, detecting them earlier, or mitigating the damages when spills do occur.

The market failure that suggests a need for Federal regulations is that there are externalities associated with spills for which there may be no economic incentive for operators to be concerned. An externality is an uncompensated direct impact of an economic activity on parties not involved in the transactions of the activity—sometimes referred to as third-party effects. Externalities can lead to increases or decreases in costs and benefits; in general, it is likely that HL spills will lead to damages to people with no role in buying or selling the HLs or damaging the environment. The value of the loss of product due to a pipeline leak may be less than the cost to the operator to address the problem. However, those who may have their health adversely affected by the spill may incur costs for which they are not compensated or may not want to incur the compromise to their health even if they were compensated. Likewise, the environmental damages due to a leak are not a cost to the operator and may go unmitigated without regulation.

Litigation or the threat of litigation may force a pipeline operator to incur some of the third-party costs resulting from a spill. In theory, an operator's expected liability for damages converts external third-party costs to private costs for the operator, thereby eliminating the market failure. However, there are a number of reasons why regulations, or regulations in combination with legal liability, may be preferable to legal liability alone as a means to correcting externalities associated with pipelines. Some of these reasons include the following:

- ***Inability or unwillingness of responsible party to pay damages*** **–** An operator may be able to avoid paying the full cost of damages through bankruptcy. Companies may even structure their businesses to limit liability by spinning off high-risk operations into separate, smaller companies for which they are not liable.[16] For severe leaks, the present

[15] http://www.moneymatters360.com/index.php/definition-of-a-natural-monopoly-2506/ (accessed August 12, 2014).

[16] Washington State Department of Ecology, Spill Prevention, Preparedness, Response Program (June 7, 2006) "Preliminary Cost-Benefit Analysis of the Oil Spill Contingency Plan Rule", p. 34–35.

value of a company and its expected future profits may be less than the damages caused by the spill.[17]

- ***Transactions*** **–** Litigation requires real resources, including the time of attorneys, judges, third-party claimants, defendants, expert witnesses, scientists, accountants, and sometimes economists, to assess and prove damages and to assign responsibility. Litigation also often involves substantial uncertainty that can take years to resolve. Regulations may reduce uncertainty relative to litigation. Additionally, enforcement costs of regulations may be less than the transaction costs involved with the legal system.

- ***Public confidence*** **–** A damaging spill resulting from an operator's failure to implement appropriate precautions erodes public confidence in the pipeline infrastructure. Although the operator who caused the spill suffers damage to its reputation, operators of other pipelines who implemented adequate precautions will also be hurt by the loss of public confidence in the pipeline system. According to a 2006 report from the National Commission on Energy Policy, public opposition to new energy infrastructure is "a major cross-cutting challenge for U.S. energy policy."[18] Public perception can be a significant consideration when setting regulatory policy.[19] The effects of a loss of public confidence are difficult to monetize and will not be included in spill-related damage awards.

If the costs associated with preventing HL spills are less than the total societal costs of harms to people and the environment and loss of product—whether the prevention costs are incurred voluntarily or by mandatory standards—it is in the public interest to incur those prevention costs.

2.2.2. Legislative – Safety Updates to the Nation's Pipeline Safety Laws

On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act (H.R. 2845).[20] This legislation marked a comprehensive update to the Nation's pipeline safety laws. This law includes the following provisions that this NPRM addresses to enhance public safety:

- The Secretary of Transportation was required to issue a report that included an evaluation of whether "integrity management system requirements"—the most intensive of inspection requirements—should be expanded to areas beyond which they are currently mandated, after considering several prescribed factors. If the report supported the need for expanding IM regulations, the Secretary was given authority to issue regulations to do so.

- Mandates the Secretary of Transportation to issue regulations to require operators of HL pipeline facilities to use LDSs where practicable and to establish technically, operationally, and economically feasible standards for the capability of such systems to detect leaks. This mandate is contingent on whether a report that DOT is required to issue

[17] Washington State Department of Ecology, Spill Prevention, Preparedness, Response Program. (June 7, 2006) "Preliminary Cost-Benefit Analysis of the Oil Spill Contingency Plan Rule", p. 34–35.
[18] Parfomak, Paul W. (January 9,2013) "Keeping America's Pipelines Safe and Secure: Key Issues for Congress" Congressional Research Service, p. 25.
[19] Ibid.
[20] https://energycommerce.house.gov/fact-sheet/pipeline-safety-regulatory-certainty-and-job-creation-act-hr-2845.

finds that it is practicable to establish such standards. This is a direct response to problems experienced in the oil spill in southwest Michigan in 2010, when the operator was unable to confirm that a leak existed for more than 12 hours while 800,000 gallons of oil was released.[21]

- Directs the Department to review requirements for pipelines buried underneath waterways and report legislative recommendations to improve existing law if it is merited.

2.2.3. Strategic – PHMSA's Goals

According to PHMSA's Strategic Plan,[22] PHMSA's mission is "to protect people and the environment from the risks inherent in transportation of hazardous materials—by pipeline and other modes of transportation." PHMSA is committed to reducing the risk of harm to people and the environment resulting from the transportation of hazardous materials by pipelines.

Risks to the public result from the potential for accidental releases from pipelines. Pipeline accidents can impact surrounding populations, property, and the environment; this leads to societal costs in the form of injuries, fatalities, and/or property and environmental damage. One of the major ways PHMSA achieves safety, environmental, and reliability goals is by increasing the consequences of failures. The proposed requirements are needed to carry out PHMSA's goals and the legislative mandates in the Pipeline Safety, Regulatory Certainty, and Job Creation Act (H.R. 2845).

PHMSA's goal is to reduce the risk of harm to people due to the transportation of hazardous materials by pipelines and other modes. Pipeline accidents, depending on their mode and severity, can cause many health hazards, including toxicity, dizziness, asphyxiation, irritation, or burns. Pipeline accidents not only have a negative impact on the environment and the economy, but can also affect health and well-being.

PHMSA's goal is to reduce the risk of harm to the environment due to the transportation of oil and hazardous materials by pipeline and other modes. Ground and waterway releases can cause environmental damage, impact wildlife, and contaminate drinking water supplies. Since some petroleum product vapors are heavier than air, they can spread and create a vapor explosion. Oil spills that spread over the permeable ground may require cleanup. Since oil products are lighter than water, spills that impact waterways can travel through or close to populated areas via storm drains and create a pathway for flammable or combustible liquids, as well as allow the resulting vapors to travel. The spread can be undetectable from the surface. Also, runoff may cause pollution.

---

[21] White, Ed. "Deal Reached Between Michigan, Enbridge over 2010Oil Spill." Downstream Today. May 13, 2015. Retrieved from http://www.downstreamtoday.com/News/article.aspx?a_id=47661&AspxAutoDetectCookieSupport=1.

[22] http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/PHMSA%20Strategic%20Plan%20_2007-2011%20with%20cover%204.pdf.

PHMSA's goal is to help maintain and improve the reliability of systems that deliver energy products and other hazardous materials in a way that increases safety and minimizes the effect of disruptions. Accidents have the potential to increase the demand for community resources. There is typically an increased demand for assistance from first responders and firefighters to control fires and from police and other law enforcement personnel to control traffic and to assist in possible evacuations. HL releases may also prompt demand for services from engineers or other public workers to deal with utility and infrastructure problems. Releases can cause business interruptions or loss of fuel supplies such as natural gas, gasoline, and home heating oil. Although the potential for releases to cause displacement of populations near or around fires or explosions is remote, these releases could cause the need for permanent or temporary shelter, which would put more strain on community resources. Combined effects on businesses, transportation, and other economic resources can exacerbate response and recovery issues.

2.3. Baseline

HL pipelines carry crude oil, refined petroleum products, volatile liquids (such as propane, butane, and ethylene), carbon dioxide, and anhydrous ammonia. The pipeline infrastructure consists of approximately 191,478 miles of currently operating HL pipeline, of which 186,543 miles are onshore and 4,935 miles are offshore.[23] Table 2 shows the total onshore and offshore HL pipeline miles reported to PHMSA as of 2012, as well as the pipeline miles inside and outside of HCAs as of 2013.

Table 2. Miles of HL Pipelines Based on Data Through 2013

	Total Miles	Total Miles Inside HCAs	Total Miles Outside HCAs
Onshore Miles	186,543	82,302	104,241
Offshore Miles	4,935	712	4,223
Total Miles	191,478	83,014	108,464

In December 2000, PHMSA issued the HL IM rule,[24] which requires pipeline operators to develop programs to assess, evaluate, and mitigate risks to their pipelines in HCAs or potentially affecting HCAs. Operator IM programs must include such elements as identifying pipelines affecting HCAs, conducting baseline and periodic reassessments of those pipelines, identifying and repairing integrity threats, and measuring program effectiveness.

[23] Original data was compiled by PHMSA. See https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?Portalpages for publicly available summary data on mileage and operators by HL commodity type. To calculate miles by onshore versus offshore, access raw data from operator annual reports at http://phmsa.dot.gov/pipeline/library/datastatistics/pipelinemileagefacilities (accessed December 20, 2014). PHMSA data for total HCA miles are publicly available at https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?PortalPages&NQUser=PDM_WEB_USER&NQPassword=Public_Web_User1&PortalPath=%2Fshared%2FPDM%20Public%20Website%2F_portal%2FPublic%20Reports&Page=HL%20IM%20Perf (accessed on December 20, 2014).

[24] 49 CFR 195.452 (2001), "Pipeline Integrity Management in High Consequence Areas," went into effect on March 31, 2001. Although initially pertaining to operators with 500 or more miles of HL pipelines, the rule was expanded to include operators with less than 500 miles of pipeline starting February 15, 2002.

Beginning in 2004, HL pipeline operators have been required to submit performance measure reports for pipeline infrastructure covered by IM programs. Table 3 depicts the performance trend for HCAs under the IM program, illustrating numbers of spills, assessments, and repairs from 2004 to 2013.[25]

Table 3. HL IM Program Performance Summary, 2004–2013[26]

Hazardous Liquid IM Performance National Summary

Date run: 7/9/2014

From 2010 - Data as of **7/8/2014**

From 2004 through 2009 - Data as of **7/8/2014**

Inter/Intra: (All Column Values) State:

Calendar Year	HCA Miles	% of Total Miles	Large Spills in HCAs	Large Spills per 10,000 HCA miles	Baseline miles completed in Year	Reassessment miles completed in Year	Total Assessment Miles completed in Year	HCA Immediate Repairs	HCA 60-day Condition Repairs	HCA 180-day Condition Repairs	HCA Pressure Test Failure Repairs	Total HCA Repairs
2013	83,006.91	43.4%	66	8.0	1,025.26	26,695.56	27,720.83	947	1,918	5,595	39	8,499
2012	79,099.68	42.5%	71	9.0	1,785.15	26,407.98	28,193.13	515	689	3,537	33	4,774
2011	78,898.34	43.0%	72	9.1	1,309.84	21,283.26	22,593.10	766	468	2,489	64	3,787
2010	78,669.92	43.2%	63	8.0	918.92	21,210.97	22,129.89	933	717	4,031	19	5,700
2009	77,222.58	43.9%	68	8.8	3,372.45		3,372.45	660	454	3,088	74	4,202
2008	76,437.93	44.0%	85	11.1	5,915.96		5,915.96	888	1,022	4,037	51	5,947
2007	73,046.06	43.0%	63	8.6	9,240.31		9,240.31	880	580	2,139	91	3,599
2006	73,484.60	44.1%	66	9.0	12,410.77		12,410.77	941	861	2,748	88	4,550
2005	72,239.86	43.3%	70	9.7	17,500.91		17,500.91	1,369	1,109	5,278	208	7,756
2004	72,239.31	43.3%	64	8.9	65,564.95		65,564.95	1,701	647	3,178	129	5,526
				Grand Total	**119,044.51**	**95,597.77**	**214,642.29**	**9,600**	**8,465**	**36,120**	**796**	**54,340**

In comparing average spills from crude oil pipelines from 1999 to 2001 with spills from 2010 to 2012, AOPL determined that spills were "down over 60 percent and spill volumes were down by nearly 50 percent. While individual pipeline incidents do occur on rare occasions, the overall trend of pipeline safety has improved." In addition, they note that in the last 10 years, the percent decrease in corrosion as a cause of releases is down by 78 percent and the percent decrease in seam and weld failures is down by 31 percent.[27]

As illustrated in Table 3, the mandatory repairs under the IM program made inside of HCAs over a 10-year period (from 2004 to 2013) totaled 54,340 ("Total HCA Repairs")—an average of 5,434 repairs per year; operators make an average of 0.25 repairs per mile over the 10-year period (54,340 total HCA repairs/214,642 total assessment miles).

Repairs are required when an operator is aware of a defect or anomaly that poses a threat to the integrity of the pipeline. Threats outside of HCAs are guided in general by 49 CFR 195.401(b)(1), which states that if an operator discovers a threat to a pipeline, the operator must correct the condition within a reasonable time, and if the condition presents an immediate hazard,

25 See http://primis.phmsa.dot.gov/iim/perfmeasures.htm; https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll? Portal Pages (accessed August 12, 2014). Reassessment miles and HCA pressure test failures were not required to be reported separately prior to 2010.

26 Numbers may not total due to rounding.

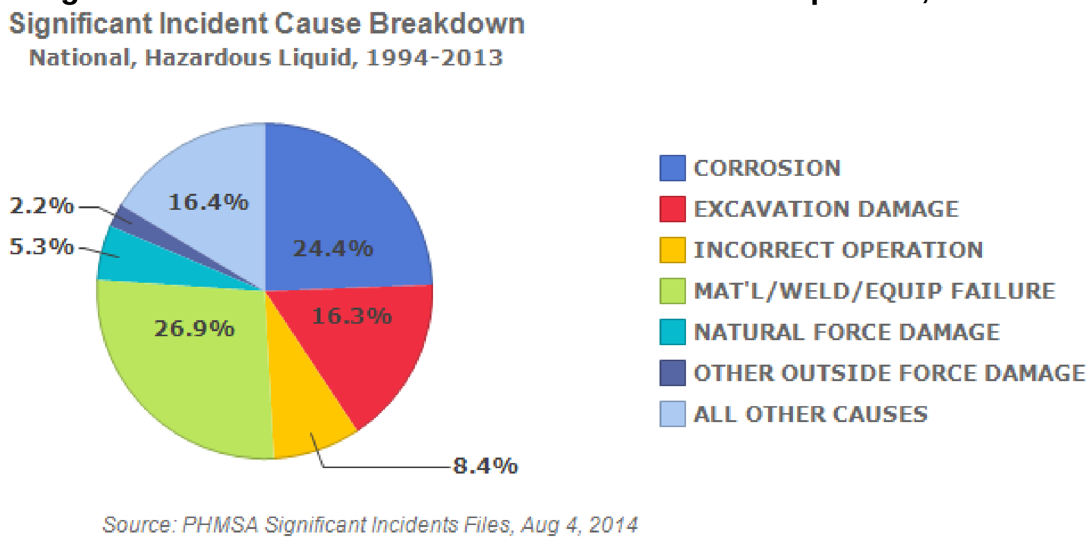
27 http://www.aopl.org/safety/improved-safety-record/ (accessed August 13, 2014).

the operator must shut the system down until the condition is corrected. HL operators are also required to have a spill plan, which PHMSA reviews and approves.[28]

2.3.1. Factors Contributing to Pipeline Failures

According to PHMSA data, the largest cause of HL incidents reported in HL pipelines since 1992 was damage caused by material/weld/equipment failure. Figure 1 shows the causes of breakdowns for all reported causes of breakdowns for HL pipelines.[29]

Figure 1. Significant Incident Cause of Breakdowns for HL Pipelines, 1994–2013[30]



2.3.2. HL Pipeline Incidents

PHMSA provides information from accident reports based on reporting criteria[31] that were in effect at the time of the incident.[32] Table 4 includes summary statistics derived from the accident reports filed by HL pipeline operators for "significant" incidents.[33]

---

[28] Additional information on the repairs and remediation can be found at http://primis.phmsa.dot.gov/comm/PipelineLibrary.htm (accessed August 15, 2012).

[29] The terms "incident" and "accident" are used interchangeably throughout this document. Typically, PHMSA uses the term "accident" for HL pipeline accidents and "incident" for gas pipeline accidents. However, PHMSA's data on the PRIMIS Web site uses the term "incident" rather than "accident" in titles accompanying charts and data tables. Therefore, this document uses the terms accident and incident interchangeably, not wanting to change the designation used in the source data documentation.

[30] To see what is included in each of the categories, see http://primis.phmsa.dot.gov/comm/reports/safety/SigPSIDet_1994_2013_US.html?nocache=2635#_liquid (accessed August 9, 2014).

[31] Under 49 CFR 195.50, HL pipeline operators are required to fill out an accident report for any accidental release of an HL that results in one or more of the following:

1. Unintentional fire or explosion.
2. Fatality or injury requiring hospitalization.
3. Releases of greater than 5 gallons (with some exceptions).
4. Estimated property damage greater than $50,000.

These reporting criteria were in effect for HL pipelines during the entire 2004 through 2013 period covered in Table 4.

Table 4. National HL: Significant Incidents Summary Statistics, 2004–2013[34]

Year	Incidents		Fatalities		Injuries		Net Barrels Lost		Property Damage (Millions $ 2013)	
	Non-HCA	HCA	Non-HCA	HCA	Non-HCA	HCA	Non-HCA	HCA	Non-HCA	HCA
2004	91	44	0	5	1	15	53,177	15,390	$149.3	$47.6
2005	75	52	2	0	0	2	23,518	22,300	$232.0	$122.4
2006	63	44	0	0	2	0	43,542	9,887	$37.4	$43.9
2007	62	47	4	0	8	2	60,158	8,498	$36.5	$26.6
2008	59	63	1	1	1	1	59,165	9,920	$79.7	$75.3
2009	65	45	3	1	1	3	25,079	6,784	$49.7	$25.1
2010	58	64	1	0	1	3	39,878	9,309	$46.3	$1,002.6
2011	70	70	1	0	2	0	46,454	10,815	$71.9	$203.1
2012	55	73	0	3	0	4	15,279	13,957	$51.6	$90.6
2013	84	77	1	0	2	3	79,005	8,533	$81.7	$180.4
Average Annual Rate	68.2	57.9	1.3	1	1.8	3.3	44,525	11,539	$83.6	$181.8

As is evident in Table 4, based on PHMSA incident data of "flagged incidents" from 2004 through 2013, there are an average of 68.2 significant incidents outside of HCAs and 57.9 significant incidents inside of HCAs each year, based on parameters assigning HCA/non-HCA status to incidents.[35] Although there are fewer incidents inside of HCAs and fewer barrels lost, average annual reported property damage is more than twice as high in HCAs as in non-HCAs. Property damage data is compiled from self-reported estimates by pipeline operators. Operators are instructed to include their best estimate of total property damage in the original report and update their estimates in a supplemental report if they determine that the actual costs are more than 20 percent or $20,000 different than the original estimates. They are instructed to include damage to their own property, including facility repair and replacement, the value of lost

---

[32] Summary statistics from these accident reports can be downloaded from http://phmsa.dot.gov/pipeline/library/datastatistics/pipelineincidenttrends (accessed December 20, 2014).

[33] "Significant" incidents are those reported by pipeline operators when any of the following specifically defined consequences occur:

1. Fatality or injury requiring inpatient hospitalization.
2. Total costs of $50,000 or more, measured in 1984 dollars.
3. Highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more.

[34] The table reflects PHMSA data as of December 17, 2014. The totals are not static over time; the numbers change depending on when PHMSA generates the report. Table 4 was compiled from PHMSA's "Pipeline Incident Flagged Files." These files contain all of the detailed data from the operator-submitted accident reports with several additional "flag" variables added by PHMSA to identify trends despite changing reporting requirements. These files can be downloaded from http://www.phmsa.dot.gov/pipeline/library/datastatistics/flagged-data-files.

[35] In the analysis of the data from PHMSA's "Pipeline Incident Flagged Files." Incidents are assigned to HCAs and non-HCAs based on whether they are labeled as "HCA" in the data file for 2002–2009 and "could be HCA" in the data file for 2010–present.

product, damages to third parties, environmental cleanup, damage assessments and damages, and other costs of the accident. Litigation costs are specifically excluded from property damage estimates.

For large spills, the updated property damage estimates reported in the accident reports are similar or identical to the cost estimates in news reports. However, there are important social costs completely missing from the estimates and some costs that are likely underestimates of the true social costs. Moreover, for major spills, the true extent of environmental damage can take years or even decades to determine. There is also considerable scientific uncertainty regarding the long-term human health effects from exposure to spilled substances.

Two of the largest categories of spill costs unlikely to be captured in property damage estimates are use and non-use values of environmental amenities. Use value for damaged ecological resources include recreational uses such as fishing, boating, swimming, camping, bird watching, and other activities at or near the spill site that people must forego during the cleanup process. Non-use value is the amount that people are willing to pay to avoid the deaths of animals killed in the spill or damage to the ecosystem even though they have no plans to visit the spill location. People may be willing to pay to avoid damages to places they have never visited because they value the existence of the habitat or want to preserve the option of visiting it someday (option value).

Non-use values may be estimated using a contingent valuation survey, which questions respondents regarding their willingness to pay to prevent damage to a habitat or animal species. Non-use values are often ignored because of the time and expense involved in constructing these estimates. Sometimes, non-use value estimates from a contingent valuation study are "transferred" for the purposes of estimating non-use values at a site different from the original study. However, for most spills, the cost in terms of lost non-use values will never be estimated and damages from a spill will be underestimated.

Because of the difficulty and expense involved in accurately assessing the true extent of environmental damages on a case-by-case basis, some States (including Florida, Washington, and New Jersey) have developed simplified formulas that can be used to estimate environmental damages based on spill volume and characteristics of the spill location.[36] However, the formulas for these estimates are designed to secure funds for the restoration of damaged ecosystems from the party responsible for the HL release and are therefore based, at least in part, on legal considerations. Therefore, in this RIA, PHMSA will use the self-reported estimates of property damage to obtain a lower bound on the benefits of the proposed requirements. Any excess of quantified costs over quantified benefits should be weighed against the unmeasured environmental damages from spills.

The dollar value of fatalities, injuries, and property damages due to HL pipeline incidents also represents societal costs. Per the Department guidance, we considered the value of a statistical

[36] Faass, Josephine (2010). "Florida's Approach to Natural Resource Damage Assessment: A Short, Sweet Model for States Seeking Compensation," Ecological Restoration, 28(1), p. 32–39.

life (VSL)—i.e., societal willingness-to-pay for avoiding a transportation fatality—to be $9.2 million.[37]

The injury values specified by the Department guidance are shown in Table 5.

Table 5. Relative Disutility Factors by Injury Severity Level (AIS)

AIS Level	AIS-1	AIS-2	AIS-3	AIS-4	AIS-5	AIS-6
Severity	Minor	Moderate	Serious	Severe	Critical	Unsurvivable
Fraction of VSL	0.003	0.047	0.105	0.266	0.593	1.000
Monetized With $9.2 Million VSL	$27,600	$432,400	$966,000	$2,447,200	$5,455,600	$9,200,000

In this analysis, we assumed that injuries associated with HL accidents are in the AIS-2 (Moderate) to AIS-5 (Critical) range.[38] The current instructions for the accident report direct the operator to include only injuries that require at least one night of hospitalization. Furthermore, nearly 65 percent of the injuries from 2004 through 2013 involved accidents from explosions. Given the likelihood and seriousness of burns for people injured from an explosion or fire, we used a simple average, of AIS-2 through AIS-5, to obtain an estimate of the cost per injury of $2.3 million.

Overall Societal Costs Associated With HL Pipelines

Table 6 presents a summary of the societal costs associated with HL pipelines inside and outside HCAs. The social costs per mile in HL pipeline that could affect HCAs are more than two times greater than the social costs for non-HCA pipeline.

Table 6. Summary of Annual Societal Costs, 2004–2013

Loss Category	Non-HCA	HCA
Fatalities	$12.0	$9.2
Injuries	$4.1	$7.6
Property Damage	$83.6	$181.8
Total Social Costs	**$99.7**	**$198.6**
HL Pipeline Miles	108,464	83,014
Social Costs per Mile	**$919**	**$2,392**

Table 7 summarizes the baseline data on the number of HL pipeline miles and operators. These estimates are derived from PHMSA, industry sources, and published reports.

[37] Guidance on Treatment of the Economic Value of Statistical Life (VSL) in the U.S. Department of Transportation Analysis – 2014 Adjustment, issued June 13, 2014.

[38] See http://www.dot.gov/regulations/economic-values-used-in-analysis (accessed August 12, 2014), "Guidance on Treatment of the Economic Value of a Statistical Life in the U. S. Department of Transportation Analyses."

Table 7. Summary of HL Pipeline Information

Baseline Parameters	
Number of operators [39]	421
Total HL pipeline mileage[40]	191,478
Total HL pipeline mileage in HCAs	83,014
Total HL pipeline mileage in non-HCAs	108,464
Estimate of number of HL pipeline operators currently exempted from Section 195.1[41]	23

2.3.3. Current Regulatory Requirements

Currently, Pipeline Safety Regulations do not apply to all HL pipelines. Exceptions include facilities that were determined not to pose a significant risk to public safety at the time the rule was promulgated. For example, pipelines used to transport HLs by gravity, gather HLs in certain rural areas, or move carbon dioxide beyond certain points in production, injection, or recovery operations were excluded from regulation by statute. PHMSA estimates that without the current proposed requirements, there would continue to be exemptions and ambiguities in the regulation of pipeline safety; thus, communities are likely to continue to experience incidents causing harm to human life and the environment from pipelines that now carry risk they did not when the laws was initially promulgated.

Extend Reporting Requirements to All HL Gravity Lines

Gravity lines are currently exempt from PHMSA regulations. PHMSA believes that the operation of gravity lines containing HLs does involve safety and environmental risks. Depending on the elevation change, a gravity flow pipeline could have more pressure than a similar pipeline with pump stations to boost the pressure. The spill volume of a pipeline leak or rupture is driven by pressure, regardless of whether the pressure is created by pumping or gravity. In addition, pipeline controllers can shut down pumps to mitigate spill volume by reducing pipeline pressure—a mitigated action that cannot be taken on a gravity line. PHMSA is seeking the collection of new information by requiring data submission similar to that collected on pipelines regulated under FR 195 lines to better understand the risks gravity lines now pose to people and the environment. There is limited information about pipeline construction quality, maintenance practices, location, and Pipeline IM. The collection of such information is authorized under the Pipeline Safety Laws, and the resulting data will assist in determining whether the existing Federal and State regulations for these lines are adequate.

Extend Reporting Requirements to All HL Gathering Lines

Gathering pipelines transport a commodity from its source to a facility for processing or to a transmission line. In the past, most gathering lines were built in minimally populated areas, used smaller-diameter pipelines that operated at lower pressures, and appeared to pose a much lower risk than other types of pipelines. The "Pipeline Safety: Updates to Pipeline and Liquefied Natural Gas Reporting Requirements" (One Rule) rulemaking revised the Pipeline Safety

[39] Based on PHMSA Annual Reports Data, March 1, 2012, http://www.phmsa.dot.gov/pipeline/library/data-stats (accessed August 15, 2012).
[40] See Tables 2 and 3.
[41] See http://www.aopl.org/pdf/API-AOPL_Comments_on_Safety_of_Onshore_Hazardous_Liquid_Pipelines_ANPRM_2_18_2011.pdf (accessed July 2, 2012).

Regulations (49 CFR Parts 190-199) to improve the reliability and utility of data collections from operators of natural gas pipelines, HL pipelines, and liquefied natural gas facilities. However, approximately 23 operators are currently exempt from submitting annual reports and incident reports.[42] PHMSA is seeking the collection of new information by requiring data submission similar to that collected on regulated gathering lines to better understand the risks the exempt gathering pipeline may now pose to people and the environment. Recent data indicate that PHMSA regulates only 3,644 miles of the approximately 30,000 to 40,000 miles of onshore HL gathering lines in the United States.[43] There is limited information about pipeline construction quality, maintenance practices, location, and Pipeline IM. The collection of such information is authorized under the Pipeline Safety Laws, and the resulting data will assist in determining whether the existing Federal and State regulations for these lines are adequate.

Require Inspection of HL Pipelines in Areas Affected by Extreme Weather, Natural Disasters, and Other Similar Events[44]

For safe operation of pipelines, operators perform periodic inspections. This proposed requirement addresses the inspection of pipelines once they are subjected to extreme weather to find flaws and damage that can lead to preventive action that averts or lessens the impact of a pipeline incident.[45] For example, pipelines along or beneath riverbeds are vulnerable to scouring from natural disasters.[46] On July 27, 2011, PHMSA issued an advisory bulletin regarding the actions that operators should consider taking to ensure the integrity of pipelines in case of flooding. In October 1994, major flooding along the San Jacinto River near Houston, TX, resulted in eight pipeline failures and compromised the integrity of several other pipelines. Similar flooding along the Yellowstone River resulted in the release of crude oil into the Yellowstone River. No official cause of the spill has been determined, but flood conditions in the river may have stirred up floating debris that damaged the pipeline.

A report by Argonne National Laboratory, Environmental Science Division, explains that “pipelines buried beneath or adjacent to rivers can be compromised over time by the erosive force of the moving water. Scouring can occur that would displace the cover materials and expose the pipe, subjecting it to additional lateral forces and possibly even causing sufficient displacement to break the pipe.”[47] According to that study, transmission pipelines, pump stations,

[42] Ibid.

[43] The Federal Government is primarily responsible for developing, issuing, and enforcing pipeline safety regulations, but the pipeline safety statutes provide for State assumption of the *intrastate* regulatory, inspection, and enforcement responsibilities under an annual certification. See http://phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=60dc8f4826eb9110VgnVCM1000009ed07898RCRD&vgnextchannel=a576ef80708c8110VgnVCM1000009ed07898RCRD&vgnextfmt=print (accessed August 9, 2014).

[44] These do not include man-made events.

[45] See Code of Federal Regulations, 49 CFR Part 195.

[46] Pipelines that cross riverbeds or lie below the seabed may be damaged due to abrasion from the ebb and flow of the water, thereby washing away the sand/clay/earth covering the pipeline. Excessive scouring causes spanning. If allowed to go uncorrected, the pipeline welds crack or the pipe ruptures from its unsupported weight.

[47] T.C. Pharris and R.L. Kolpa, “Overview of the Design, Construction, and Operation of Interstate Liquid Petroleum Pipelines.” November 2007. See http://corridoreis.anl.gov/documents/docs/technical/APT_60928_EVS_TM_08_1.pdf (accessed August 15, 2012), page 29.

compressor stations, processing facilities, storage tanks, metering stations, and buried distribution pipelines are highly vulnerable to natural hazards such as earthquakes, landslides, dam inundation, and particularly flooding.[48]

According to one study (done for the United States Geological Survey and the California Geological Survey), historically there have been many oil and gas pipeline failures due to ground shaking.[49] The authors note, "Buried pipelines are vulnerable to permanent ground deformation and wave propagation (shaking). Ground deformation can include fault rupture, landslide, and liquefaction and associated lateral spreading and settlement. Pipe damage mechanisms include: compression/wrinkling, joint weld cracking/separation (particularly for oxy-acetylene welds), bending/shear resulting from localized wrinkling, and tension."[50] In addition, the study notes that "landslides can load buried pipelines in a similar manner to fault rupture. Pipelines crossing block landslide failures (but moving only several meters) laterally are put into shear at both edges of the block. If they run through longitudinally, they are put into tension at the top of the slide, and into compression at the toe. In catastrophic landslide failures, the pipe may be left unsupported."[51]

Require Assessments of HL Pipelines in Non-HCAs Using ILI Tools at Least Every 10 Years

Assessments would provide critical information about the condition of these pipelines, including the existence of internal and external corrosion and deformation anomalies.

Under the IM program, an operator must perform periodic integrity assessments (i.e., continual integrity evaluation and assessment) on line segments that could affect HCAs at intervals not to exceed 5 years.

The risk represented by the segment should be used to establish the appropriate assessment interval within the 5-year period. Operators may extend the intervals to more than 5 years if a reliable engineering evaluation and other external monitoring activities show the pipe to be in good condition or if a new integrity assessment technology that the operator plans to use is not readily available.

Current regulations allow pipeline operators to determine the best method(s) of assessing the structural integrity of their pipelines, using one or more of the following three approaches: ILI, hydrostatic testing, or direct assessment.

PHMSA data presented in a written statement by Cynthia L. Quarterman, PHMSA Administrator, "Preventing Spills from Hazardous Liquid Pipelines through Integrity Management,"[52] show that 92 percent of the IM assessments are performed using one of the ILI assessment methods. Eight percent of IM inspections use other tools, while 7 percent of IM inspections (the majority of those using other tools) use hydrotest inspection or pressure testing.

[48] Ibid. page 40.

[49] "SPA Risk LLC and MMI Engineering, Inc. "The Shakeout Scenario, Supplemental Study." See http://www.colorado.edu/hazards/shakeout/pipelines.pdf (accessed August 15, 2012).

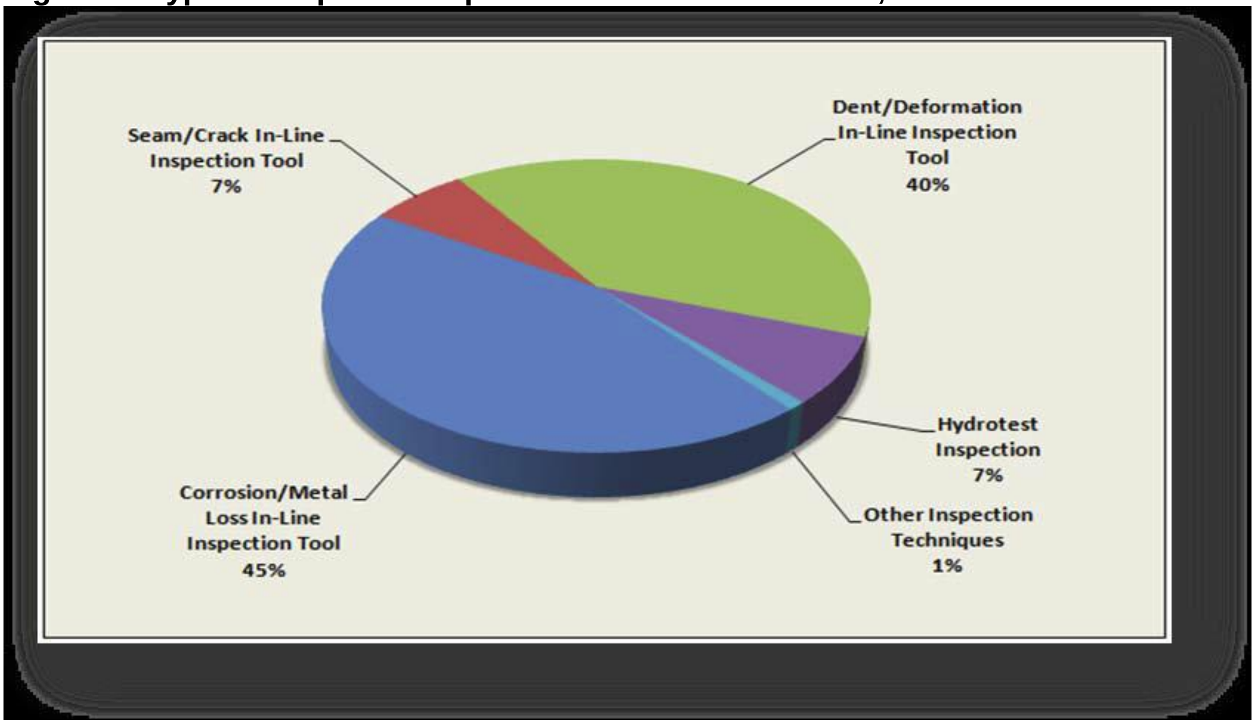
[50] Ibid. page 3.

[51] Ibid. page 3.

[52] Source: Testimony given before the Subcommittee on Railroads, Pipelines, and Hazardous Materials Committee on Transportation and Infrastructure, United States House of Representatives, July 15, 2011.

Figure 2 is representative of the current allocation of the various assessment methodologies used to assess pipelines in areas that could affect HCAs.[53]

Figure 2. Types of Pipeline Inspections Under the IM Rule, 2001–2009



Expand the Use of LDSs for All HL Pipelines

Currently, Part 195 contains mandatory leak detection requirements for HL pipelines that could affect an HCA. According to the PHMSA Advisory Bulletin,[54] "many of the operators with higher mileage have configured their pipelines into networks, sometimes collecting product from multiple sources and delivering product to multiple destinations, making the leak detection process complex. At the same time, we recognize that in some cases the engineering analysis performed on point-to-point pipeline systems has determined that installing a computer-based LDS does not offer substantial improvements in leak detection capability beyond that of a simple manual line balance calculation process."

According to a report titled "Leak Detection Technology Study" completed for PHMSA in December 31, 2007, the numbers of LDSs vary by the types of pipeline construction, operation, and environments in which they operate.[55] Pipeline infrastructure is composed of a wide variety of materials installed over many decades in environments as widely diverse as Florida and Alaska. Environmental factors, many of which can fluctuate over the course of a day, a month, or

[53] See http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/House%20T&I%20Integrity%20Management%20on%20Haz%20Liq%20Pipes_July%2015%202010.pdf (accessed August 15, 2012).

[54] https://www.federalregister.gov/articles/2010/01/26/2010-1497/pipeline-safety-leak-detection-on-hazardous-liquid-pipelines#h-6 (accessed August 9, 2014).

[55] See http://phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/S10-080623-002-Signed.pdf (accessed February 7, 2012).

a year, affect the performance of these LDSs. These include soil type, moisture, temperature, topography, and seismicity. Operational factors also fluctuate widely due to seasonal or demand factors. Technical capabilities to detect leaks vary in terms of sensitivity, accuracy, and responsiveness. Also noted is the fact that pipeline size, length, operating parameters, and instrumentation design will affect the detection time.

A study conducted for the Department notes that "seepage leaks represent a hard to identify pollution source and safety concern. If left until they are discovered visually on surface after affecting water quality, such leaks will cause great damage that is very expensive and difficult to remediate. Early detection of leaks can greatly reduce the loss of product from the pipeline and danger of pollution."[56]

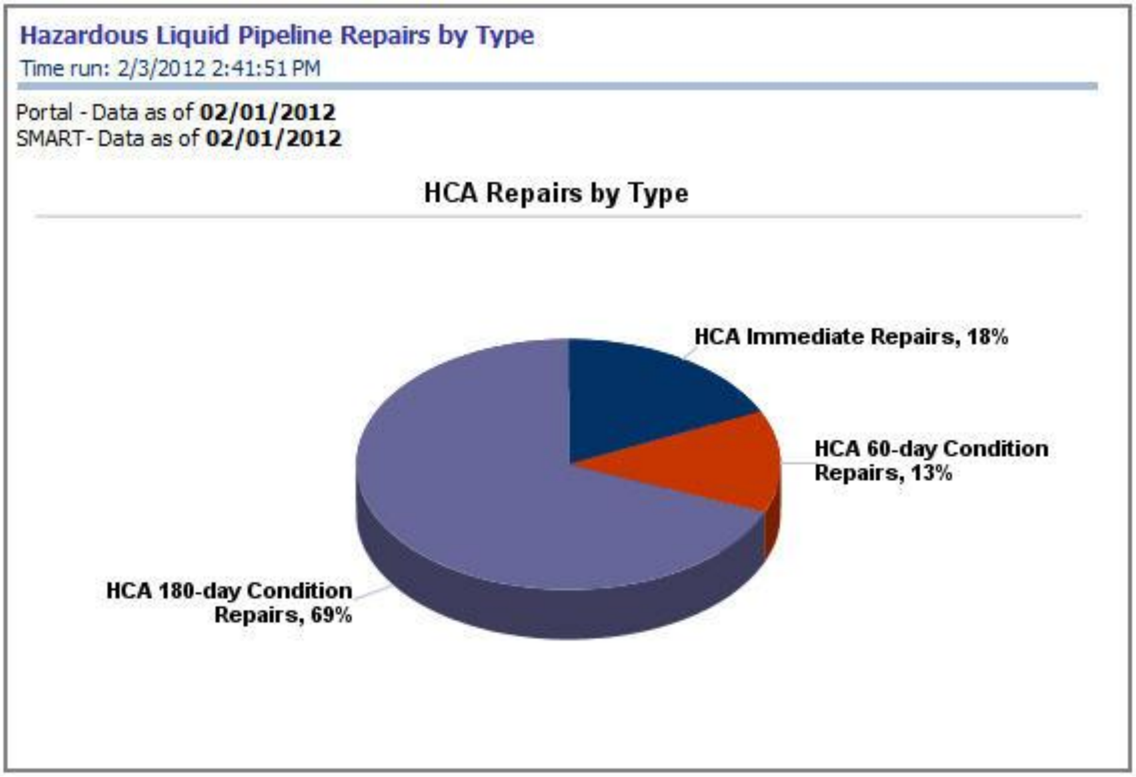
Modify the IM Repair Criteria and Apply Those Same Criteria to Pipelines That Are Not Subject to the IM Requirements

The repairs carried out since the Liquid IM Rule's inception include the three types of prioritized repairs occurring inside of HCAs that are required by the Liquid IM Rule, as well as all other repairs that were made by operators as a result of their IM-related inspections. Currently, the Liquid IM rule requires three types of prioritized repairs: (1) those that must be addressed immediately, (2) those that must be addressed within 60 days, and (3) those that must be addressed within 180 days.

Figure 3 depicts the percentages of the various types of HCA repairs (Immediate, 60-day, and 180-day) carried out since the Liquid IM Rule's inception.

[56] Leak Detection Technology Study for the PIPES Act H.R. 5782, December 31, 2007. See http://phmsa.dot.gov/pv_obj_cache/pv_obj_id_3C99D9FDAEEFC6E1ED639A2773D56ED62DD23200/filename/S10-080623-002-Signed.pdf (accessed August 27, 2014).

Figure 3. HL Pipelines, HCA Repairs by Type, 2004–2010



The NPRM allows for additional conservatism to be incorporated into the existing repair criteria, and an adjusted schedule will be established to provide greater uniformity. The 60-day and 180-day repair categories will be consolidated into a single 270-day category, mandating that HCA pipes that formerly had 60-day and 80-day deadlines for repair must now meet the 270-day required deadline. There will be an extended timeframe for pipelines in need of repair that are located outside of HCAs.

The proposed requirement is extended to pipelines not subject to IM requirements. As noted above, operators already make a large number of pipeline repairs outside of HCA.

Increase the Use of ILI Tools (Smart Pigs)[57]

PHMSA is proposing to require that all HL pipelines in areas that could affect an HCA be made capable of accommodating ILI tools within 20 years, unless the basic construction of a pipeline will not accommodate the passage of such a device.[58] Existing regulations require new pipelines to be able to accommodate ILI tools. The effect of this proposal would be to retrofit or replace

[57] Smart pigs are devices that move inside a pipeline propelled by product flow and travel throughout the length of a pipeline. They are used during inspections, primarily to detect wall thinning caused by ordinary corrosion. Smart pigs provide information on the condition of the line, as well as the extent and location of any problems. For additional information, see http://primis.phmsa.dot.gov/comm/FactSheets/FSSmartPig.htm?nocache=2850 (accessed August 11, 2012).

[58] Short sections of pipe (such as manifolds, station piping, tank farm piping, and smaller lines) and other lines that—due to their design or configuration (such as low-pressure lines, telescoping lines, sharp bends, and mainline valves that are not full opening)—ILI tools cannot go through will not accommodate ILI tools.

pipeline that would not be replaced within 20 years following publication of the final rule so that the pipeline can accommodate an ILI tool. Expanding the ability of operators to use smart pigs in performing integrity assessments will further promote public safety and the protection of the environment in these high-risk areas. The proposed regulation will not require the modification of any pipeline facilities listed in § 195.120(b). PHMSA is also including a provision requiring that pipelines within newly identified HCAs be modified to accommodate ILI tools before the performance of the 5-year baseline assessment required under § 195.452(d)(3). As with new pipelines, operators will be allowed to petition the Administrator for finding that the basic construction of a pipeline or an emergency will not permit the accommodation of a smart pig. PHMSA is also removing the size limitation referenced in § 195.120(b)(5) to encompass the use of non-metallic piping and the potential development of ILI tools that could be used to perform integrity assessments of such piping in the future.

PHMSA is proposing to limit the circumstances where a pipeline can be constructed without being able to accommodate a smart pig. Under the current regulation, an operator can petition the Administrator for such an allowance for reasons of impracticability, emergencies, construction time constraints, and other unforeseen construction problems. PHMSA believes that an exception should still be available where the basic construction of a pipeline makes that accommodation impracticable and for emergencies, but that the other, less urgent circumstances listed in the regulation are no longer appropriate. Accordingly, the allowances for construction-related time constraints and problems would be repealed.

ILI tools are an effective means of assessing the integrity of a pipeline, and broadening their use will improve the detection of anomalies and prevent or mitigate future accidents in high-risk areas.

Considerations Relating to Tool Tolerance

The accuracy and tolerance of ILI tools is a consideration in various sections of the proposed rule. Based on PHMSA’s review of inspection data, PHMSA concluded that operators should be explicitly required to consider the accuracy of their ILI tools. The IM rule requires action based on an analysis of ILI results that considers the depth of anomalies. Depth is a factor that goes into calculating remaining strength. Depth is also a repair requirement in itself if corrosion exceeds a certain percentage of wall thickness or if dents exceed certain percentages of pipe diameter. ILI results analysis can produce a point estimate, but there is an inherent inaccuracy in collecting the data, as there is for most experimental measurement devices. In reviewing IM inspection data, PHMSA discovered that some operators were not considering the accuracy (i.e., tolerance) of ILI tools when evaluating the results of the tool assessments. As a result, random variation within the recorded data led to both overcalls (i.e., an anomaly was identified to be more extreme than it actually was) and undercalls. Overcalls result in repair of some anomalies that might not actually meet repair criteria. Undercalls can result in anomalies that exceed specified repair criteria going un-remediated. PHMSA could have specified a method of accounting for tool accuracy. There are, however, many factors that affect tool tolerance, including the ability of the analyst. Operators perform verification digs to measure some anomalies and compare them to the ILI findings. This could indicate a tool is performing better than the nominal tolerance. PHMSA decided to be prescriptive in requiring that each operator consider tool tolerance in its analysis of ILI results but left it to the operator (performance requirement rather than design requirement) to determine how to do this. The Corrosion and Metal Loss ILI Tool and the Dent and Deformation ILI Tool are most often used, due to their ability to detect the most commonly occurring types of anomalies in HL pipelines. These two types of inspection tools account for some 84 percent of all HL pipeline inspection miles. Other tools and tests serve the purposes as well and are used to check for more specific—but much less commonly occurring—concerns. Since the requirement relating to tool tolerance is a performance requirement, the cost to operators will depend on how they approach the analysis.

IM Assessment, Evaluations, and Repairs

The Hazardous Liquid Pipeline Integrity Management Program was created to ensure pipeline integrity in areas with the highest potential for adverse consequences (areas that could affect HCAs), promote a more rigorous and systematic management of pipeline integrity and risk by operators, maintain oversight of pipeline operator integrity plans and programs, and increase the public's confidence in the safe operation of the Nation's pipeline network. IM program regulations require operators to analyze risks and focus increased attention on safety, especially the portions of their pipeline that pose the highest risk. This increased attention must include physical inspection (assessment) of the pipe using ILI, pressure testing, or direct assessment; remediation of anomalous conditions following the assessment; continual evaluation of the pipeline; application of additional preventive and mitigative measures; and development of performance measures.

Current regulations allow pipeline operators to determine the best method(s) of assessing the structural integrity of their pipeline inside HCAs, using one or more of the following three approaches: ILI, hydrostatic testing, or direct assessment. PHMSA also allows operators to employ alternative assessment methods if they can be shown to be effective. The proposal requires ILI assessments unless (1) the operator demonstrates to the satisfaction of PHMSA that the pipeline is not capable of using this tool, (2) the operator demonstrates that the use of an alternative assessment method will provide a substantially equivalent understanding of the condition of the pipeline, and (3) the operator provides notices to PHMSA. A person qualified to perform that covered task must analyze the data obtained from an ILI tool to determine if a condition could adversely affect the safe operation of the pipeline. Uncertainties in any reported results (including tool tolerance) must be considered as part of that analysis. Based on these assessments, operators must take prompt action to repair any defects that could reduce a pipeline's integrity.

According to AOPL and the American Petroleum Institute (API),[59] operators conduct risk assessments for impacts on pipeline that could affect HCAs as part of their IM program. They note that "pipeline IM programs harness cutting-edge diagnostic technologies to scan their pipelines, and the latest analytic software to review inspection results and isolate potential issues for maintenance. The goal of the IM program is to identify and treat symptoms long before they grow into a problem."

[59] See http://www.aopl.org/wp-content/uploads/2014/04/PSE-2013-Annual-Safety-Perf-Report_O.pdf, page 10 (accessed August 11, 2014).

Clarifying Other Requirements

Changes are expected to improve protection of the public, property, and the environment by closing regulatory gaps where appropriate and ensuring that operators are increasing the detection and remediation of unsafe conditions and mitigating the adverse effects of pipeline failures.

2.4. Timeframe for the Analysis

PHMSA estimates that the economic effects of this rulemaking, once finalized and adopted, will be sustained for many years into the future. The timeframe depends on the requirement and the effectiveness of the requirement. For those areas where the service life of the pipe is impacted, the timeline used in these analyses is 50 years. For other requirements, the timeline is determined by the service life of the product and the technological advances. Notwithstanding this, because of the difficulty of and uncertainty associated with forecasting industry effects into the far future, we assume different time periods to quantify and monetize the costs and benefits and demonstrate net effects, and we use requirement-specific timeframes to outline, quantify, and monetize the total costs and total benefits and demonstrate total net effects of the proposal.

2.5. Identification of Available Alternative Approaches and the Consequences of the Alternatives

The alternatives considered by PHMSA are discussed separately in the following sections that review each requirement of the rule. The “No Action” alternative for the proposed rule would maintain the status quo and, to the extent that incidents continue to occur on pipelines not subject to PHMSA regulations, the potential benefits of reduced societal costs of deaths, injuries, and property damages will be forgone.

2.6. Overview of the Costs and Benefits Associated With the Proposed Rule Requirements

2.6.1. Costs

The costs for the proposed rule are based on expected impacts on operators of HL pipelines. There may be other costs that are not quantified because PHMSA does not have the information necessary to do so. PHMSA invites comments on the cost estimates made herein on the different requirements.

To the extent that estimated costs can be quantified, the following sections discuss information available to PHMSA for each requirement. With the exception of the reporting requirements, most of the other requirements are performance-directed rather than design-directed, and the costs to operators will depend on the methods they use in complying.

PHMSA invites comments on each of the estimated costs noted as follows under each proposed requirement. There are both direct and indirect costs associated with implementing the proposed rule; these depend on a variety of events.

2.6.2. Benefits

The economic value of reported incidents, including fatalities, injuries, property damages, environmental damages, and other damages associated with the incidents, represent the potential benefits of eliminating incidents; those values do not include the benefits associated with avoiding costs of chronic health hazards, which are unreported.

Although PHMSA is convinced that the quality and accuracy of the data will be improved and that pipeline safety will be enhanced, it is difficult to forecast with certainty or quantify all the benefits of the rule.

Non-quantifiable benefits that are directly or indirectly related to this rulemaking include the following:

- Streamlined regulations and increased regulatory certainty for pipeline operators.

Unquantified Benefits

The unmeasured benefits are organized into three broad categories: Reporting Omissions, Public Health and Environmental Costs, and Social Costs.

<u>Reporting Omissions</u>

The following categories of spill costs are not included or are underreported in the data collected from PHMSA accident reports:

- ***Litigation Costs*** **–** The instructions for the PHMSA accident reports specifically tell operators not to include litigation costs in the reported property damage estimates.[60] However, litigation requires real resources, including the time of attorneys, judges, third-party claimants, defendants, expert witnesses, scientists, accountants, and sometimes economists, to assess and prove damages and to assign responsibility. One study estimated that for the 1990 Arthur Spill, the Natural Resource Damage Assessment (NRDA)[61] cost 0.6 to 2.8 million dollars, or $126 per barrel spilled.[62] Litigation also often involves substantial uncertainty that can take years to resolve. By preventing spills, this proposal can prevent years of litigation.
- ***Injuries not Requiring Hospitalization*** **–** The accident reporting form instructs operators to report only injuries that involved an overnight hospital stay. From a cost-benefit standpoint, the willingness to pay to avoid less severe injuries should be included in estimates of social costs as well.

[60]Instructions for accident reporting in PHMSA form F-7000-1. See http://phmsa.dot.gov/pv_obj_cache/pv_obj_id_9459B8EDB8F01D777F6C64B053C508C37A510300/filename/HL Accident Instructions - PHMSA F 7000-1 rev 7-2014.pdf.

[61] An NRDA is a process to estimate the extent of environmental injury caused by a spill and the type and amount of restoration needed.

[62] Advanced Resource International, "Economic Impact of Oil Spills: Spill Unit Costs for Tankers Pipelines, Refineries and Offshore Facilities," cited on p. 111 of Volume II of the Regulatory Analysis for the Rural Onshore Hazardous Liquid Low Stress Pipelines (Phase 2).

- ***Evacuations –*** Unless the cost of evacuations and the subsequent disruptions are included in a settlement or the operator compensates victims, these costs are not likely to be included in property damage estimates.
- ***Other Third-Party Costs –*** Some third-party costs will not be included in accident reports because no claim is filed and the operator does not know the true extent of damages to third parties. Although operators are required to report cleanup costs as property damage, cleanup can sometimes take years and the total costs of cleanup may not be known for years.

Public Health and Environmental Impacts

The avoided environmental costs through spill prevention are often the largest category of benefits. Although this proposed requirement applies to non-HCA pipelines that by definition will not affect USAs, the areas outside of HCAs are subject to the same categories of environmental damages as HCA pipelines. These categories include the following:

- ***Lost Use Value –*** During the cleanup process, the contaminated environmental resource may not be available for recreational or commercial users. The lost value to users of the resource due to an accident should be counted in the social costs of a spill. The lost use value may be measured during an NRDA or other study. However, estimating lost use value takes time and resources. The operators are not going to have much, if any, information regarding lost use value when they fill out the accident report.
- ***Non-Use Value –*** Non-use environmental values reflect people's willingness to pay to preserve species, ecosystems, and habitats that they may never visit but value their existence. The only way to measure non-use values is through contingent valuation surveys that are often costly to conduct. In the case of the Exxon Valdez oil spill, which may not reflect average non-use value costs for HL pipeline releases, the estimated non-use value cost was approximately three times the size of the final settlement.[63]
- ***Long-Term Health Consequences –*** There is a great deal of scientific uncertainty regarding the long-term effects of exposure to carcinogenic substances such as benzene in the aftermath of a spill. However, there are numerous toxic substances in spilled crude oil and other HLs for which some people would be willing to pay to avoid exposure.
- ***Social Cost of Carbon –*** An HL spill may release some greenhouse gases into the atmosphere as the liquid evaporates. Highly volatile liquids will evaporate quickly upon release, while evaporation of heavier liquids may be minimal.

Socio-Economic Impacts

Public Confidence: A damaging spill resulting from an operator's failure to implement appropriate precautions erodes public confidence in the pipeline infrastructure. Although the operator who caused the spill suffers damage to its reputation, operators who implemented adequate precautions will also be hurt by the loss of public confidence in the pipeline system.

[63] Exxon's settlement with the Federal Government and State of Alaska for the Exxon Valdez oil spill was $1.15 billion. A contingent valuation survey estimated that the non-use value losses attributable to the spill were $3 billion nationally. Portney, Paul (1994) "The Contingent Valuation Debate: Why Economists Should Care," 8(4) pp. 3–17.

According to a 2006 report from the National Commission on Energy Policy, public opposition to new energy infrastructure is "a major cross-cutting challenge for U.S. energy policy."[64] Public perception can be a significant consideration when setting regulatory policy.[65] The effects of a loss of public confidence are difficult to monetize and would not be included in the reported property damage in accident reports.

- ***Level Playing Field:*** By requiring all operators to conduct inspections at least once every 10 years using an ILI tool, the operators who do conduct inspections at least once every 10 years using an ILI tool will not be taking on higher costs relative to operators who have not been conducting these inspections at these intervals.
- ***Energy Security:*** The prevention of pipeline accidents also protects against disruption of the energy supply. Furthermore, PHMSA does not expect that these requirements will reach any of the "significant adverse effect" thresholds that would warrant an Energy Impact Analysis, including reduction in energy supply.

PHMSA invites comments on each of the benefits noted as follows under each proposed requirement. There are positive direct benefits associated with implementing the rule, and there are also indirect benefits that are contingent on a variety of events.

The rule is expected to reduce risk by reducing the likelihood of an incident occurring and reduce the consequences of an incident should it happen. In addition, the rule is expected to enhance PHMSA's ability to do the following:

- Understand, measure, and assess the performance of individual operators and the industry as a whole.
- Integrate pipeline safety data in a way that will allow a more thorough, rigorous, and comprehensive understanding and assessment of risk.
- Improve the data and analyses PHMSA relies on to make critical, safety-related decisions and improve PHMSA decision making.
- Facilitate PHMSA's allocation of inspection and other resources based on a more accurate accounting of risk.
- Reduce the time PHMSA spends on gathering data from multiple sources to carry out pipeline oversight responsibilities.

If the rule is effective, there will be fewer accidents, resulting in fewer associated deaths, injuries, and property damage. The societal costs of those deaths, injuries, and property damage will also be reduced. In a joint letter to PHMSA on August 17, 2011, API and AOPL stated, "We

[64] Parfomak, Paul W. (January 9, 2013) "Keeping America's Pipelines Safe and Secure: Key Issues for Congress." Congressional Research Service, p. 25.
[65] Ibid.

are committed to continuous improvement in pipeline performance and safety, with an ultimate goal of zero accidents."[66]

The estimated costs and benefits may be affected by many factors that are not a direct result of the NPRM. Other regulatory actions that have been promulgated affect the status and level of actions that operators may take in the absence, or in spite of this, NPRM. PHMSA is uncertain about how operators will act in the future. For example, PHMSA cannot predict at this time if operators will do more frequent inspections or just as many inspections as required by this rule. If operators end up doing more frequent inspections, will there be a need to do more frequent repairs? More frequent repairs will be more costly but will also provide a better margin of safety. PHMSA seeks comments on these issues.

A summary of discounted costs and benefits is provided in Appendix A.

2.7. Consideration of the Loss of Energy Supplied

PHMSA does not expect that these requirements will reach any of the "significant adverse effect" thresholds for an Energy Impact Analysis listed below:

- Reductions in crude oil supply in excess of 10,000 barrels per day.
- Reductions in fuel production in excess of 4,000 barrels per day.
- Reductions in coal production in excess of 5 million tons per year.
- Reductions in natural gas production in excess of 25 million mcf (1,000 cubic feet) per year.
- Reductions in electricity production in excess of 1 billion kilowatt-hours per year or in excess of 500 megawatts of installed capacity.
- Increases in energy use required by the regulatory action that exceed any of the thresholds above.
- Increases in the cost of energy production in excess of 1 percent.
- Increases in the cost of energy distribution in excess of 1 percent.
- Other similarly adverse outcomes.

[66] August 17, 2011, letter to the Honorable Cynthia Quarterman, Administrator, Pipeline and Hazardous Materials Safety Administrator, from Steve Wuori, President, Liquids Pipelines Embridge, Inc., Chairman of AOPL Board, and Harry Pefanis, President and COO, Plains All American Pipeline, L.P., Chairman, API Pipeline Subcommittee.

3. Regulatory Impact Analysis of the Proposed Requirements

The rule has eight discrete requirement areas. The costs and benefits associated with each requirement are derived from PHMSA data, industry estimates in response to the ANPRM (as noted in the NPRM), or published sources.

Requirement Area #1 – Extend Reporting Requirements to All HL Gravity Lines

Proposed Action: PHMSA is proposing to extend certain reporting requirements to HL gravity lines. Specifically, 49 C.F.R. § 195.1(b)(2) states that Part 195 does not apply to the "[t]ransportation of a hazardous liquid through a pipeline by gravity."

§ 195.58 Report submission requirements.

- **(a)** ***General.*** Except as provided in paragraph (b) of this section, an operator must submit each report required by this part electronically to PHMSA.
- **(b)** ***Exceptions.*** An operator is not required to submit a safety-related condition report (§ 195.56) or an offshore pipeline condition report (§ 195.67) electronically.
- **(c)** ***Safety-Related Conditions.*** An operator must submit to the applicable State agency a safety-related condition report required by § 195.55 for an intrastate pipeline or when the State agency acts as an agent of the Secretary with respect to interstate pipelines.
- **(d)** ***Alternate Reporting Method.*** If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety (OPS), PHMSA.

Alternatives Considered

Alternative 1: No Action (Baseline—Maintains the Status Quo)

PHMSA would be unable to gather the information required to evaluate the risk posed by gravity lines. The collected risk information will allow PHMSA to assess the need for regulation of gravity lines and devise appropriate regulatory policies if warranted. From the PHMSA perspective, gravity lines potentially involve safety and environmental risks. Depending on the elevation change, a gravity flow pipeline could have more pressure than a pipeline that has pump stations to boost the pressure. The spill volume of a pipeline leak or rupture is driven by pressure, regardless of whether the pressure is created by pumping or gravity.

Alternative 2: Regulate Gravity Flow Pipelines Carrying Ethanol

This alternative was originally considered because transportation of ethanol by pipelines can be problematic due to its high oxygen content, making it more corrosive. Also, ethanol's greatest hazard is its flammability; it has a more flammable range than gasoline. Ethanol does not produce visible smoke and has a hard-to-see blue/orange flame. Ethanol and some ethanol blends can conduct electricity, whereas gasoline does not.[67] In reality, ethanol is not transported by pipeline frequently, and if it is, it is generally a denatured product.

Commenters to the ANPRM stated that the current exception for gravity flow pipelines is appropriate and nevertheless expressed the view that the exception should not apply to pipelines that transport ethanol. This alternative was rejected for the same reasons as the No Action Alternative. PHMSA concluded that the benefits of applying pipeline safety requirements to prevent incidents with gravity flow lines carrying all HLs outweigh the associated burdens.

Alternative 3: Apply Part 195 Requirements to All Gravity Flow Pipelines Carrying HL, Including Rural Gravity Lines

Currently, only certain requirements apply to rural gravity lines. This alternative was considered by PHMSA because transportation of any HL pipeline can pose a risk due to corrosion that could then result in leakage or rupture of the pipeline and/or flammability. In reality, PHMSA does not have evidence that rural HLs transported by gravity flow pipeline present the same risks, and the costs to comply with 195 are likely to outweigh benefits. Therefore, PHMSA rejected the alternative to remove all current exemptions.

Analysis of Costs and Benefits of the Proposed Action

Analysis of Costs

PHMSA does not know the quantity of miles of gravity-fed lines there are, nor do they know the location of these lines. PHMSA estimates that there are between three and five operators accounting for approximately 17[68] to 28[69] miles of affected gravity-fed lines.

PHMSA estimates that some of the costs associated with this requirement will be absorbed by HL pipeline operators who have gravity lines under other current regulatory requirements. For purposes of calculating costs, PHMSA estimates that there are four operators impacted by this requirement, which will need to adhere to the requirements in the NPRM in the future. The estimated number of miles of gravity pipeline affected is approximately 23 miles.

PHMSA does not know for certain where gravity lines are located. Also, since 49 C.F.R. § 195.1(b)(2) Part 195 does not apply to the "[t]ransportation of a hazardous liquid through a pipeline by gravity," PHMSA has not gathered any HL accident reports on gravity lines. Due to not knowing the location or the incident statistics, we assume two different scenarios for calculating costs. The proposed regulatory changes would allow PHMSA to obtain information on the location of gravity lines and other information that can be used to evaluate risk.

Costs of Reporting and Recordkeeping

Costs of Reporting – PHMSA expects the costs will depend on the type of operation and the experience of the operator with reporting requirements. PHMSA's staff has observed that

[67] http://www.ethanolrfa.org/page/-/rfa-association-site/pdf/module2.pdf.
[68] See "Advance Notice of Proposed Rulemaking, Pipeline Safety: Safety of On-Shore Hazardous Liquid Pipelines, Docket No. PHMSA-2010-0229 – Comments of American Petroleum Institute and Association of Oil Pipe Lines," February 18, 2011, page 5.
[69] Seventeen miles was based on three operators; proportionally five operators would yield 28 miles.

typically there is a learning curve when operators are subject to new requirements. Based on past experience with different rules, PHMSA estimates that the cost to add additional information to the annual report will be nominal. Several employees (including compliance officers whose mean hourly wage is estimated to be $37.11 and a secretary/administrative assistant whose mean hourly salary is estimated to be $18.10)[70] may need to be involved in the preparation of annual reports, including recording the information, signing off, and transmitting it to PHMSA. The cost for compliance officers and administrative support is $55.21. The composite hourly average salary for all HL employees expected to be involved in providing the reports is $27.61 ($55.21 total/2 persons); the fully loaded cost of labor is $41.42 ($27.61 * 1.50).

Based on previous recordkeeping experience, PHMSA's technical staff estimates that the additional time to include these parameters in their annual reports is 1 hour per operator. Therefore, the total labor costs are $166 ($41.42 fully loaded labor costs * 4 operators). The additional cost per operator per year would be approximately $41. It is assumed that the format of the information provided to PHMSA in the annual reports will be acceptable to the States and no additional reports or telephone communication will be needed to comply with the requirement.

Costs of Recordkeeping **–** PHMSA expects the cost of the required recordkeeping to be nominal. Some of the required records will be kept electronically, while others will be kept on paper. In the case of those kept electronically, the required recordkeeping will necessitate a company clerk entering data and in some cases scanning materials. In the case of those records kept on paper, the required recordkeeping will necessitate a company clerk placing materials in file folders, placing the file folders in file cabinets, and retrieving files when needed. It may also necessitate a system for signing materials in and out. Finally, in some cases, physical recordkeeping may necessitate the acquisition of file cabinets and file folders by some operators. Based on previous experience with recordkeeping, typically a clerk is the person who maintains the records in accordance with the recordkeeping requirements.[71]

The average hourly salary, including benefits, for a clerk is estimated at approximately $30 ($19.88 Bureau of Labor Statistics (BLS) hourly wage rate for an office clerk in the oil industry * 1.5 overhead = $29.82).[72] PHMSA's technical staff estimates that the average time to perform these tasks would be about 0.5 hour per month, or 6 hours per year. The total cost per operator per year would be approximately $180 ($30 hourly wage rate for a clerk * 6 hours). The total annual costs for recordkeeping are estimated to be $720 ($180 cost of recordkeeping per operator * 4 operators). There is no expectation that the recordkeeping would require operators to hire additional personnel. Neither is there an expectation that the recordkeeping would require operators to acquire new computers or peripherals.

[70] See http://www.bls.gov/oes/current/naics4_211100.htm#11-0000 (accessed July 30, 2014).
[71] See http://www.bls.gov/oes/current/naics4_486100.htm#43-0000 (accessed July 30, 2014).
[72] See http://www.bls.gov/oes/current/naics4_211100.htm#11-0000 (accessed July 30, 2014).

Table 8. Estimated Costs of Complying With the Proposed Reporting Requirements for Gravity Lines for Four Operators With 23 Miles of Gravity Lines

Total Costs – Reporting and Recordkeeping			
10-Year Costs			Annual
Undiscounted	3%	7%	Total
$8,900	$7,800	$6,700	$900

The present value of costs over a 10-year period is $7,800 discounted at 3 percent and $6,700 discounted at 7 percent. The annual costs for this rule are the same every year. Therefore, the annualized costs are $900 at a 7-percent or 3-percent discount rate.

PHMSA seeks comments on the location of the gravity lines, the number of miles impacted by this requirement, and the estimated costs.

Analysis of Benefits

PHMSA does not have any information indicating that accidents have occurred on gravity lines in prior years. PHMSA notes that gravity lines can and do involve safety and environmental risks. Depending on the elevation change, a gravity flow pipeline could have more pressure than a pipeline with pump stations to boost the pressure. The spill volume of a pipeline leak or rupture is driven by pressure, regardless of whether the pressure is created by pumping or gravity.

PHMSA believes that reporting is essential to manage risk. Data from reports are used by the Agency to identify trends, provide performance measures, and understand the causes and consequences of pipeline incidents. The data are also used by PHMSA to demonstrate the regulatory effectiveness and identify where changes should be explored. Reporting requirements are in place for all pipelines except for the gathering lines currently unregulated. Reporting on the latter segment of the pipeline will help the Agency have a more complete picture of the risk involved.

In its Strategic Plan, PHMSA notes that one of the Agency's challenges is to understand and target risk, which requires a systematic approach to risk management, including a "comprehensive understanding of the factors contributing to risk and the ability to focus resources in those areas that pose the greatest risk." One of PHMSA's strategies for dealing with this challenge is to "improve data collection and analysis, collect the right data to evaluate risks from unregulated entities, and improve the transparency of information and public awareness of pipeline and hazardous materials safety issues."[73] The benefits may include reducing incidents, enhancing incident response, and increasing public confidence.

Comparison of Costs and Benefits

The cost of this reporting requirement is extremely low relative to the potential for improvements in pipeline operations that may occur in the future. The total compliance costs are expected to be approximately $900 per year. The benefits are not quantified but are expected to justify the costs

[73] PHMSA Strategic Plan (2012–2016).

of the action. PHMSA believes that the low costs of the requirement are justified. PHMSA invites comments on this analysis.

Requirement Area #2 – Extend Certain Reporting Requirements to All HL Gathering Lines

Proposed Action: PHMSA is proposing to add 49 C.F.R. § 195.1(a)(5) to require that the operators of all gathering lines comply with requirements for submitting annual, safety-related condition and incident reports.

Alternatives Considered

Alternative 1: No Action (Baseline—Maintains the Status Quo)

Under this option, PHMSA would maintain existing requirements for reporting by taking no action. However, PHMSA believes that this would not effectively support PHMSA's safety mission.

Although taking no action would eliminate additional compliance costs, there would be no benefits ensuing from the proposal and PHMSA would continue to lack important safety information about these pipelines.

Alternative 2: Require Different Reporting for Some Operators

PHMSA considered establishing different requirements for the large and small operators who may be among the 23 estimated to be affected by the proposed rule, basing the requirements on estimated differences in expected costs and benefits. PHMSA is aware that some regulations, rules, and Government policies place a disproportionate burden on small firms. Consequently, to promote entrepreneurship, Government agencies have sometimes granted small businesses preferential regulatory treatment, such as exemptions from legislation and regulations or extended deadlines for compliance.

PHMSA judged that these considerations were not sufficient to recommend reporting requirements based on business size. This option was not chosen because PHMSA concluded that allowing disparate reporting would not meet its informational needs by leaving a significant number of operators outside the reporting requirements. The Agency believes that reporting must provide relevant information that is useful for the decision-making needs of groups for whom the information is provided. PHMSA determined, therefore, that not requiring the smaller operators to report would dampen the regulation's effectiveness and that special regulatory treatment would not, in fact, help small businesses. PHMSA believes that although there may be a learning curve for small entities, with practice and guidance—which PHMSA is willing to provide—small operators will learn how to comply with the reporting requirements.

Alternative 3: Extend Certain Reporting Requirements to All HL Gathering Lines

Since the estimated reporting costs for this requirement were on average less than $1,000 per year per operator, PHMSA considered allowing voluntary reporting by operators under the assumption that they may report because of the low costs. It is precisely because the reporting costs are low that PHMSA rejected this alternative. The potential benefits to society are likely to justify the low level of reporting costs.

Analysis of Costs and Benefits of the Proposed Action

Analysis of Costs

The compliance costs are the costs associated with reporting data to PHMSA. In order for PHMSA to effectively analyze safety performance and pipeline risk of gathering lines, PHMSA needs basic data about those pipelines. The agency has the statutory authority to gather data for all gathering lines [49 U.S.C. § 60117(b)], and that authority was not affected by any of the provisions in the Pipeline Safety Act of 2011. Given the information is recorded and readily available (including the number of miles of pipeline), it is assumed that there are no costs to gather the information for submission. PHMSA seeks public comments regarding the accuracy of this assumption.

For the **annual reports**,[74] [75] PHMSA assumes the following:

- Costs are associated with the time to provide the additional information required under this proposal and submit the form.
- Approximately 23 operators are impacted, each having to complete accident report forms annually.
- Several employees (including a compliance officer whose mean hourly wage is estimated to be $37.11 and a secretary/administrative assistant whose mean hourly salary is estimated to be $18.10)[76] may need to be involved in the preparation of annual reports, including recording the information, signing off, and transmitting it to PHMSA. The total for these employees is $55.21. The composite hourly average salary for all HL employees expected to be involved in providing the reports is $27.61 ($55.21 total/2 persons); the fully loaded cost of labor is $41.42 ($27.61 hourly rate * 1.50 overhead for indirect expenses valued at 50 percent).
- Operators will spend a minimum of 18 hours completing the annual report form.[77] There may be some reductions in labor hours in successive years as operators become more familiar with reporting requirements. For this analysis, we are projecting the same amount of hours from year to year.
- Each operator would be required to prepare a separate report for gathering lines transporting different types of HL. However, PHMSA expects that the 23 operators impacted by the requirement have only one type of product, so PHMSA estimates approximately one report for each of the 23 entities.

---

[74] Annual report template can be found at http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=2d1357c3eee3d110VgnVCM1000009ed07898RCRD&vgnextchannel=bc79c0124500d110VgnVCM1000009ed07898RCRD&vgnextfmt=print.

[75] Reporting Requirements for Hazardous Liquid Pipeline Operators: Hazardous Liquid Annual Report. OMB Control Number: 2137-0614. Expiration Date: December 31, 2015.

[76] See http://www.bls.gov/oes/current/naics4_211100.htm#11-0000 (accessed July 30, 2014).

[77] Source: "Information Collection Supporting Statement – Reporting Requirements for Hazardous Liquid Pipeline Operators: Hazardous Liquid Annual Report." OMB Control Number 2137-0614. Docket No. PHMSA 2013-0003.

The annual cost to all 23 operators for preparing and submitting annual reports is expected to be approximately $17,148 annually (18 hours * $41.42 hourly rate * 1 report * 23 operators)—approximately $746 per operator per year ($17,148/23).

For the **incident reports**,[78] PHMSA assumes the following:

- Costs are associated with the time to provide the information and submit the incident report form. Given the information is recorded and readily available, it is assumed that there are no costs to gather incident report information for submission.
- Approximately 23 operators are impacted, each having to complete incident report forms annually.
- Several employees (including a compliance officer whose mean hourly wage is $37.11 and a secretary/administrative assistant whose mean hourly salary is $18.10)[79] may need to be involved in the preparation of annual reports, including recording the information, signing off, and transmitting it to PHMSA. The total is $55.21. The composite hourly average salary for all HL employees expected to be involved in providing the reports is $27.61 ($55.21 total/2 persons); the fully loaded cost of labor is $41.41 ($27.61 * 1.50).
- PHMSA regulates only 3,644 miles of the approximately 30,000 to 40,000 miles of onshore HL gathering lines in the United States. The average number of miles not regulated is estimated to be between 26,000 and 36,000. This translates to between 1,130 and 1,565 miles per operator (26,000 miles/23 operators and 36,000 miles/23 operators).
- PHMSA estimates that impacted operators could prepare between approximately 1 report (17 incidents * 23 operators impacted/421 total number of HL operators) and 1.3 reports (24 incidents * 23 operators impacted/421 total number of HL operators) annually. PHMSA is assuming that incident rates on gathering lines are similar to other lines and seeks comment on this assumption.
- PHMSA estimates that operators will spend a minimum of 10 hours preparing the report.[80]
- The cost burden estimate does not take into account the time to investigate the incident prior to filing the report.

The annual cost of preparing and submitting incident reports for all 23 operators impacted is approximately between $414 (10 hours * $41.42 hourly rate * 1 report) and $538 (10 hours * $41.42 hourly rate * 1.3 reports)—approximately between $18 ($414/23) and $23 ($538/23) per operator per year.

---

[78] Incident report template is at http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=2d1357c3eee3d110VgnVCM1000009ed07898RCRD&vgnextchannel=bc79c0124500d110VgnVCM1000009ed07898RCRD&vgnextfmt=print.

[79] See http://www.bls.gov/oes/current/naics4_211100.htm#11-0000 (accessed July 30, 2014).

[80] Source: "Supporting Statement – Pipeline Safety: Transportation of Hazardous Liquids by Pipeline: Recordkeeping and Accident Reporting." OMB Control Number 2137-0047. Docket No. PHMSA-2013-0061.

For the **safety-related conditions reports**,[81] PHMSA assumes the following:

- Costs are associated with the time to provide the information and submit the safety-related report form. Given the information is readily available, it is assumed that there are no costs to gather incident report information for submission.
- Several employees (including a compliance officer whose mean hourly wage is estimated to be $37.11 and a secretary/administrative assistant whose mean hourly salary is estimated to be $18.10)[82] may need to be involved in the preparation of annual reports, including recording the information, signing off, and transmitting it to PHMSA. The total for these employees is $55.21. The composite hourly average salary for all HL employees expected to be involved in providing the reports is $27.61 ($55.21 total/2 persons); the fully loaded cost of labor is $41.42 ($27.61 * 1.50).
- Approximately 23 operators are impacted.
- Operators will spend at a minimum 6 hours completing the forms.[83]
- The cost burden estimate addresses the new requirement for these operators to complete a safety-related conditions report and does not take into account existing requirements, such as the time required to perform an onsite investigation of the incident prior to filing the report.
- According to PHMSA's technical staff, they expect there to be no more than one safety-related condition report per year per operator. This is a maximum, as PHMSA believes that there would be fewer reports.

The annual cost of preparing and submitting safety-related reports for all 23 operators impacted is $5,716 (6 hours * $41.42 hourly rate * 1 report * 23 operators)—approximately $249 per operator per year.

The total annual cost for preparing and submitting all reports required by this proposed rule is expected to be between approximately $23,278 ($17,148 for annual reports + $414 for incident reports + $5,716 for safety-related condition reports) and $23,402 ($17,148 for annual reports + $538 for incident reports + $5,716 for safety related condition reports.) This is approximately between $1,012 and $1,017 per operator per year. The average per-year cost for preparing all three reports is $23,340 [($23,278 + $23,402)/2]—approximately $1,015 per operator.

[81] See www.phmsa.dphmsaot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=2d1357c3eee3d110VgnVCM1000009ed07898RCRD&vgnextchannel=bc79c0124500d110VgnVCM1000009ed07898RCRD&vgnextfmt=print.

[82] See http://www.bls.gov/oes/current/naics4_211100.htm#11-0000 (accessed July 30, 2014).

[83] Source: "Supporting Statement – Reporting of Safety-Related Conditions on Gas, Hazardous Liquid and Carbon Dioxide Pipelines and Liquefied Natural Gas Facilities." OMB Control No. 2137-0578. Docket No. PHMSA-2014-0005.

Table 9: Total Costs for Requirement Area #2[84]

Total Costs			
10-Year Costs			Annual
Undiscounted	3%	7%	Total
$233,400	$205,100	$175,400	$23,300

The present value of costs over a 10-year period is $205,100 discounted at 3 percent and $175,400 discounted at 7 percent. The annual costs for this rule are the same every year. Therefore, the annualized costs are $23,300 at a 7-percent or 3-percent discount rate. PHMSA requests public comments on the above estimates of costs.

Analysis of Benefits

PHMSA believes that reporting is essential to manage risk. Data from reports are used by the Agency to identify trends, provide performance measures, and understand the causes and consequences of pipeline incidents. The data are also used by PHMSA to demonstrate the regulatory effectiveness and identify where changes should be explored. Reporting requirements are in place for all pipelines except for the gathering lines that are currently unregulated. Reporting on the latter segment of the pipeline will help the Agency have a more complete picture of the risk involved.

In its Strategic Plan, PHMSA notes that one of the Agency's challenges is to understand and target risk, which requires a systematic approach to risk management, including a "comprehensive understanding of the factors contributing to risk and the ability to focus resources in those areas that pose the greatest risk." One of PHMSA's strategies for dealing with this challenge is to "improve data collection and analysis, collect the right data to evaluate risks from unregulated entities, and improve the transparency of information and public awareness of pipeline and hazardous materials safety issues."[85] The benefits may include reducing incidents, enhancing incident response, and increasing public confidence.

Comparison of Costs and Benefits

The cost of this reporting requirement is extremely low relative to the potential for improvements in pipeline operations that may occur in the future. The total compliance costs are expected to be approximately $23,340 per year, or $1,015 per operator. The benefits are not quantified but are expected to justify the costs of the action. PHMSA believes that the low costs of the requirement are justified. PHMSA invites comments on this analysis.

[84] Totals are rounded to the nearest 100 dollars.
[85] PHMSA Strategic Plan (2012–2016).

Requirement Area #3 – Require Inspections of Pipelines in Areas Affected by Extreme Weather, Natural Disasters, and Other Similar Events

Proposed Action: PHMSA is proposing to require that operators perform an inspection within 72 hours after the cessation of weather, natural disaster, and other similar events or as soon as the affected area can be safely accessed if a pipeline is affected by flooding, hurricanes, tornados, earthquakes, landslides, and other such events. PHMSA proposes that operators, post-event, be required to evaluate Right-of-Way (ROW) conditions at waterway crossings and in offshore areas in performing those inspections. Operators would also be required to take appropriate remedial measures based on the results of those inspections, including initiating reductions in operating pressure, conducting additional surveys (e.g., to verify the remaining depth of cover over a buried pipeline), and remediating any unsafe conditions.

Current Practices: FR 195.452, PHMSA guidance documents and the recommended practices (RPs) of API assign responsibilities to HL pipeline operators for the inspection of pipeline ROWs regularly under normal operating conditions and in the aftermath of natural disasters. The requirements proposed here provide additional specificity to already existing duties and more certainty regarding regulatory requirements.

Baseline Inspection Requirements for HL Pipelines

Pipeline ROWs

Currently under § 195.412, operators of HCA and non-HCA onshore HL steel pipelines are required to inspect the surface conditions along onshore HL pipeline ROWs with ground or air patrols at least 26 times a year, with no more than 3 weeks between inspections. The purpose of these patrols is to identify conditions on the ground that may pose a threat to the pipeline, such as construction and excavation, areas of dead vegetation and other potential indicators of leaks, damaged or missing pipeline markers, unauthorized ROW activities, and erosion or earth movement. The post-disaster inspections within 72 hours after a disaster or once conditions are safe would be similar.

Pipeline Water Crossings

Operators of onshore HL HCA and non-HCA pipelines that cross under navigable bodies of water must inspect each crossing at least once every 5 years to determine their condition. These inspections are generally carried out by divers using probes to ensure that the depth of cover is adequate for safe operations and to identify washouts or other unsafe conditions that need to be corrected to avoid an accidental release.[86] For example, if the inspection reveals that scour has exposed a section of the pipeline to the currents of the river, the operator can shut down that segment of pipeline until repairs are made. In the case of flooding, a flyover or inspection by divers may reveal that the flooding conditions have created a new channel exposing the pipeline to the threat of rupture due to scour or damage from debris. During a flood, an unmarked exposed pipeline can also create a hazard for navigation and for rescue workers. By marking the

[86] PHMSA Enforcement Guidance, Operations, and Maintenance.

location of the pipeline, the pipeline can prevent boats from colliding with the exposed pipeline, potentially causing a rupture and safety hazard for boats.

Offshore Pipelines

Under § 195.413, operators of HCA and non-HCA offshore HL pipelines in the Gulf of Mexico and its inlets must conduct periodic underwater inspections of their pipelines that are in navigable waterways less than 15 feet deep. If the operator discovers that the pipeline is exposed or poses a hazard to navigation, it must report the pipeline location to the National Response Center within 24 hours, mark the location for navigators within 7 days, and rebury the pipeline or provide protection equivalent to burial within 6 months.

RPs and Guidelines Regarding Inspections and Natural Disasters

Although 195.413 and 195.412 do not explicitly require inspections following a natural disaster or extreme weather event, many operators routinely conduct these post-disaster inspections in accord with longstanding PHMSA guidance documents and RPs of API.

According to the RPs in API's Bulletin 2HINS,[87] companies shut down drilling and production operations and evacuate personnel in advance of a hurricane. After the storm has passed and it is safe to fly, companies will conduct flyovers of onshore and offshore infrastructure, including pipelines, to look for damage and spills. Once it is safe, the companies will also send crews to physically assess infrastructure. If damage is detected on offshore pipelines, operators hire divers, make repairs, and conduct safety inspections before resuming operations. Any damaged onshore pipelines are also assessed, repaired, and inspected before resuming operations. Operators make prearrangements with suppliers to ensure that they have the required resources to effectively respond to a hurricane and resume operations as soon as it is safe to do so. A PHMSA Advisory Bulletin regarding hurricanes, issued September 1, 2011, closely tracks with API's RPs.

PHMSA has published Advisory Bulletins in the Federal Register notifying HL pipeline operators that conditions created by natural disasters can constitute an "unusual operating condition that can adversely affect the safe operation of a pipeline."[88] Inspections in the event of a natural disaster may be necessary for compliance with the regulatory requirements for planning for and responding to unusual and potentially unsafe operating conditions. In an Advisory Bulletin issued July 27, 2011, PHMSA urged operators to conduct frequent patrols and overflights as well as inspections by divers at water crossings during and immediately following flood conditions. The requirement proposed here simply ensures that at least one of these inspections occurs within 72 hours of the natural disaster or once conditions are safe.

Alternatives Considered

Alternative 1: No Action (Baseline—Maintains the Status Quo)

By not taking action, there would be gaps in pipeline safety. Although taking no action would eliminate additional compliance costs, it would also eliminate benefits.

---

[87] http://www.api.org/news-and-media/hurricane-information/hurricane-preparation (accessed December 20, 2014).

[88] Pipeline Safety: Potential Damage to Pipeline Facilities Caused by Flooding. Federal Register, July 27, 2011, Notices, p 44985.

Alternative 2: Inspect All Pipelines Subject to This Requirement by Hydro Pressure Testing
Hydro testing was considered because high test pressure will eliminate all possible defects, thus ensuring that a proper safety margin is maintained. This alternative was rejected because it is much more expensive than the other ROW inspection methods (such as patrols and inspections by divers) and would not provide any information regarding potential hazards outside of the pipeline.

Alternative 3: Provide Guidance for Adoption by States
PHMSA believes that this alternative may prove infeasible because PHMSA cannot be sure that the States may want to or be able to adopt mandatory guidance. PHMSA has had experience in studying the issue of State-administered programs. The group that studied the Gas DIMP rule noted that States typically have not uniformly adopted recommended approaches in the past. Even though the costs associated with this approach are low, PHMSA decided against this approach because the benefits may not be realized, since the guidance may not be adopted by the States.

Analysis of Costs and Benefits of the Proposed Action

PHMSA's goal is to ensure uninterrupted safe operation. This requirement is designed to minimize disruptions to the oil supply that can occur as a result of natural disasters. These inspections also allow operators to detect hazardous conditions such as exposed pipeline in waterways during flooding; earth movement around the pipeline from an earthquake; damage due to a buildup from ice or snow; damage due to fire, lightning, or wind; and submersion of equipment critical for safe operation of the pipeline. By detecting these conditions early, an operator can take steps to prevent ruptures and large-scale releases.

Table 10 lists the significant incidents that occurred on pipeline ROWs due to weather-related conditions from 2010 through 2014. As Table 10 shows, according to PHMSA accident report data, there were 12 natural force incidents along HL pipeline ROWs from 2010 through 2014. On average, these incidents generated $34.7 million in property damage losses annually. Going all the way back through 2004, natural force incidents did not cause any fatalities or injuries.

Table 10. Natural Force Significant Incidents on Pipeline ROWs, 2010–2014[89]

Accident Date	Location	Accident Sub-Cause	Commodity	Property Damage (Millions) (2013 $)	Gross Loss (Gallons)
7/1/2011	Laurel, MT	Heavy Rains/Floods	Crude Oil	139.72	63,378
7/29/2013	Tioga, ND	Lightning	Crude Oil	16.99	865,200
8/13/2011	Onawa, IA	Heavy Rains/Floods	Refined Petroleum	7.94	28,350

[89] Compiled from PHMSA accident report data which is publicly available at http://phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=fdd2dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print (accessed January 4, 2014.)

Accident Date	Location	Accident Sub-Cause	Commodity	Property Damage (Millions) (2013 $)	Gross Loss (Gallons)
8/13/2013	Littleton, CO	Heavy Rains/Floods	HVLS	4.92	479,010
7/21/2012	Port Arthur, TX	Lightning	HVLS	1.18	130,914
7/15/2011	Tekema, NE	Heavy Rains/Floods	HVLS	0.99	4,200
8/7/2014	Yoder, WY	Lightning	Crude Oil	0.66	84
9/12/2013	Pinon, NM	Heavy Rains/Floods	HVLS	0.59	104,622
2/12/2014	Cleveland, OH	Earth Movement	Refined Petroleum	0.20	300
1/11/2010	Lake Charles, LA	Temperature	HVLS	0.17	93,954
3/30/2010	Salisbury, MO	Earth Movement	HVLS	0.12	27,552
2/9/2014	Munger, MI	Temperature	Refined Petroleum	0.02	755
			5-Year Total	**173.49**	**1,798,319**
			Annual Average[90]	**34.70**	**359,664**

In addition to the incidents reported in Table 10, a 2012 PHMSA report to Congress described other significant releases due to flooding."[91] These accidents included the following:

- In October 1994, flooding of the San Jacinto River in Harris County, TX, caused a release of approximately 36,000 gallons of HLs, including crude oil, diesel fuel, gasoline, and a highly volatile liquid, after 7 days of flood conditions scouring exposed 36 of the 69 pipelines crossing under the river. Accidental releases occurred at eight of the exposed pipelines.[92]
- In September 2005, Hurricane Katrina washed away a levee, resulting in a spill of 3,245 barrels of crude oil.

Although natural force damage incidents along pipeline ROWs only accounted for 9 of the 552 significant HL spills from 2010 through 2013, they were some of the largest and most damaging. The accident in Laurel, MT, is the third worst property damage loss from all causes over the past 10 years.

The hazards created by natural disasters have the potential to cause ruptures resulting in sudden, large releases with large volume losses occurring within minutes of the accident. Additionally, flood-related accidents can be especially costly because of contamination of drinking water systems or sensitive ecosystems.

---

[90] Because of reporting delays, data for 2014 may not capture all relevant incidents. Therefore, the annual average reported in Table 10 may be a slight underestimate.

[91] PHMSA Report to Congress, Results of Hazardous Liquid Incidents at Certain Inland Water Crossings Study, http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_F7EE2DB31D71255F6E1E3683FCDDC2A6635A1000/filename/Haz%20Liq%20Inci%20at%20Certain%20Inl%20Wat%20Cross%20Study%20-%2012-27-12.pdf (accessed January 3, 2014).

[92] Woodyard, Chris (1996). "Safety Panel Faults Design of Pipelines, Flood in 1994 Led to River Blaze." Houston Chronicle, September 5, 1996.

As described above, under current PHMSA guidance and industry RPs, most operators inspect ROWs following disasters. This may be one of the reasons that the incidence of natural force damage events along ROWs is relatively low in recent years. Making the requirement for post-disaster inspections explicit is intended to provide certainty to regulated operators and to lessen the likelihood of sudden large releases that could have been prevented by acting on information obtainable through inspections.

Analysis of Costs

The challenge of estimating the costs associated with this requirement is that it requires inspections after a wide variety of events. These include but are not limited to natural disasters from weather events such as hurricanes,[93] tornadoes, heavy rains that can lead to floods,[94] and earthquakes that affect pipelines in different physical ways. Pipelines of different lengths may be affected. Post-disaster inspections are usually conducted routinely,[95] so the costs associated with this requirement are due to the inspection process being explicitly moved up to within 72 hours of post-event time or once conditions become safe.

In some cases, pipelines are temporarily shut down or operate at lower pressure due to conditions created by natural disasters such as hurricanes or floods. In these instances, operators already have a strong financial incentive to perform the inspections required to resume operations as quickly as possible. Likewise, PHMSA guidance regarding flooding and water crossings advises operators to conduct frequent inspections during and after flood conditions.[96] The 72-hour requirement provides additional clarity and certainty to the requirements for pipeline operators to plan for and respond appropriately to unusual and potentially unsafe operating conditions. The proposed requirement also promotes fairer competition between operators who are diligent about monitoring ROW conditions following a disaster and operators who do not exercise the same due diligence.[97]

Inspection Cost for Weather-Related Events:

1. <u>Annual Number of Post-Event Inspection Miles</u>
   PHMSA assumes that on average, there will be approximately 134 earthquakes, 6 hurricanes, and 5 major floods per year. Based on discussions with PHMSA's staff, we assume that 300 miles of pipeline will be inspected after each earthquake and major flood and 3,000 miles after each hurricane. This amounts to 59,700 inspection miles conducted 72 hours post-event.

[93] The National Oceanic and Atmospheric Administration estimates that there are an average of 5.8 hurricanes per year. See http://www.nhc.noaa.gov/pastprofile.shtml (accessed August 16, 2012).
[94] The National Council for Resource Development estimates about five major flood events per year. See Thirsty for Answers, page 8, Figure B.4.
[95] See http://www.api.org/news-and-media/hurricane-information/hurricane-preparation.aspx (accessed July 31, 2014).
[96] PHMSA 2011-0177. Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, Federal Register, Volume 76, No 144, July 27, 2011, Notices.
[97] The Washington State Department of Ecology made a similar argument about creating a "level playing field" by codifying guidance into mandatory regulations in a 2006 cost-benefit analysis of a proposed oil plan contingency regulation. WAC 173-182 Oil Spill Contingency Plan Rule, Preliminary Cost Benefit Analysis, June 7, 2006, p. 10.

2. Marginal Cost per Mile of Post-Event Inspections
   PHMSA expects air patrols to be the most common form of post-event inspection. The required biweekly air patrols along ROWs cost approximately $50 per mile.[98] If the air patrols costs 50 percent more during the 72-hour time period following the event than during normal conditions and if the post-event inspection counts as 1 of the required 26 patrols per year, then the marginal cost of the post-event inspection is approximately $25 per mile. PHMSA requests public comments on the cost of the proposed post-event inspection on a per-mile basis.

3. Annualized Cost of Post-Event Inspections
   The annual cost of the 72-hour inspection requirement is $1.5 million ($25 per mile * 59,700 miles).

The above cost estimate assumes that operators would not need to perform an additional inspection or patrol in response to this requirement. Instead, the estimate assumes that these inspections are performed currently, or that the inspection would count toward the 26 annual inspections of ROW pipeline required by existing regulations. In addition, the cost estimate does not account for cost of repairs following these inspections because PHMSA assumes such repairs would happen in the absence of this rule—although there may be some delay in performing the repairs in the absence of this rule compared to if the rule is in place. Operators are required to have plans for such emergency conditions and can prearrange to secure the resources necessary for an appropriate response to a disaster. The increase for emergency services could be higher than 50 percent, but PHMSA engineers assume that this is a reasonable assumption given adequate pre-disaster planning. As discussed above, operators routinely monitor conditions along ROWs post-disaster in accordance with PHMSA guidance and industry best practices and in order to resume operations following a weather event such as a hurricane. The $1.5 million estimate does not account for the operators who may already be conducting inspections within the timeframe proposed in this requirement, so the actual cost of the proposed requirement could be lower. Because the cost varies depending on the jurisdiction and on the emergency service provided, it is difficult to estimate the cost of these services. PHMSA requests public comments on the above cost estimate.

Analysis of Benefits

To the extent operators do not currently conduct post-disaster inspections within 72 hours following the event, this requirement would help prevent post-disaster releases along ROW water crossings and mitigate damages from some leaks through earlier detection. However, PHMSA does not know when operators conduct these inspections currently. The benefits would be similar to those derived from preventing or mitigating spills on any system, including savings due to early detection, reduced remediation costs, and reduced emergency response costs.

To the extent operators do not currently conduct post-disaster inspections within 72 hours following an event, PHMSA believes that the proposed action would help reduce property damage, water damage, and soil contamination. Prevention and early detection would provide

[98] "Regulatory Impact Analysis for Application of Safety Regulation to Rural Onshore Hazardous Liquid Low Stress Pipelines (Phase II)," Volume II, p. 28, prepared by Jack Faucett Associates, published May 11, 2010.

benefits to the public as well as industry by reducing the remediation, emergency response, and disposal costs.

PHMSA also believes that there may be some health benefits associated with the action. The full environmental and health benefits are not quantified. As mentioned previously, property damage estimates also do not capture non-use values, and it often takes years to assess full cleanup costs and the lost use value of environmental amenities during cleanup.

To the extent operators do not currently conduct post-disaster inspections within 72 hours following an event, operators would know sooner when the pipelines are vulnerable and take steps sooner to correct vulnerabilities. The inspections may also find leaks earlier than they otherwise may be found and therefore more of the product would be saved and there would be a reduction in losses.

It is difficult to assess this rule based on average historical losses alone because, as noted above, inspections of this type are routine and PHMSA Guidance and industry RPs already require operators to inspect ROWs for dangerous conditions caused by natural disasters. To the extent that these inspections already occur within 72 hours of a natural disaster or as soon as conditions are safe, recent historical data already includes the benefits of these inspections.

Benefits Calculations

As reported in Table 10, the average annual losses from natural force damage along ROWs is $34.7 million. Assuming that the inspections are 10 to 30 percent effective at reducing losses, the annualized benefits[99] range from $3.47 million to $10.41 million. This estimate assumes that no operator is inspecting their pipeline within 72 hours following a disaster. To the extent operators already comply with this proposed requirement, the benefits would be less. PHMSA requests public comments on its assumptions.

Quantified Net Benefits

The annualized net benefits of this rule range from $2.0 million to $8.9 million.

Table 11. Quantified Net Benefits Post-Disaster Inspection Rule (Millions of 2013 $)

Net Benefits			
10 Year Costs			Annual
Undiscounted	3%	7%	Total
$55	$48	$41	$6

PHMSA is aware that the results are sensitive to the effectiveness of the inspections in reducing property damages and lost product and also the increased costs due to the 72-hour requirement. PHMSA invites comments on the analysis, including but not limited to the cost per mile of

[99] Because annual benefits are constant over time, the annualized benefits do not change with the discount rate.

performing the ROW inspections required by existing regulations, the extent operators would perform the post-event inspection required by this proposed rule by plane, the number of pipeline miles each year that would be affected by the proposed requirement, the assumption that this proposed requirement would increase the inspection cost per mile by 50 percent, and the effectiveness—in terms of reducing social costs—of performing inspections within 72 hours after an event instead of when they are performed currently. PHMSA requests comments on its estimates and assumptions.

Interaction With Other Proposed Requirements

Although this requirement affects HCA and non-HCA pipeline along ROWs, the benefits are not expected to be significantly impacted by the other proposed requirements in this rule. Other requirements work by extending reporting requirements, LDS requirements, or ILI requirements. None of these other mechanisms have a significant impact on the types of losses the ROW inspection requirements are intended to prevent, because none of these tools can be used to monitor conditions outside of the pipeline along the ROW. Although LDSs could potentially reduce the time it takes to detect a leak or rupture due to a hazard created by a natural disaster, most of the benefits of the rule are derived from the prevention of sudden ruptures, which often result in a high volume of liquid being lost in a relatively short time. These releases and resulting damages can be severe even with a properly functioning LDS. For example, during the worst natural force spill in Table 10—the rupture in Laurel, MT, in July 2011—the LDS was functional. Additionally, under IM, pipelines that could affect HCAs are already required to have LDSs. Because of the potential to affect drinking supplies or sensitive habitats, many of the pipeline water crossings already have an LDS and will not be affected by the proposed requirement for LDSs for new non-HCA pipeline.

Request for Comments

PHMSA requests comments on the following questions:

1. How should PHMSA define the end of the disaster and the start of the proposed 72-hour rule?
2. Is the proposed 72-hour rule reasonable? Should another time period be used instead? Please provide the basis to support your recommendation.
3. How soon do operators normally conduct inspections following these natural disasters or severe weather-related events?

Requirement Area #4 – Require HL Pipeline in Non-HCAs Be Assessed at Least Once Every 10 Years Using ILI Tools

Proposed Action: PHMSA is proposing to require that operators perform periodic assessments of pipelines that are not already covered under the IM program requirements in § 195.452. Specifically, the proposed § 195.416 would require operators to assess non-IM pipelines with an ILI tool at least once every 10 years. Other assessment methods could be used if an operator provides the OPS with prior written notice that a pipeline is not capable of accommodating an ILI tool. The written notice provided to PHMSA must include a technical demonstration of why the pipeline is not capable of accommodating an ILI tool and what alternative technology the operator proposes to use. The operator must also detail how the alternative technology would provide a substantially equivalent understanding of the pipeline's condition in light of the threats that could affect its safe operation. Such alternative technologies could include hydrostatic pressure testing or appropriate forms of direct assessment.

Existing IM regulations require assessments of pipeline with tools capable of detecting corrosion and deformation anomalies inside of HCAs every 5 years. However, PHMSA proposes that a 10-year interval is sufficient for pipelines outside HCAs that do not present the same level of risk. The longer interval will reduce the cost burden on operators without sacrificing safety.

The individuals who review the results of these periodic assessments would be subject to the operator qualification requirements in Subpart G of Part 195 and would need to consider any uncertainty in the results obtained, including ILI tool tolerance,[100] in determining whether any conditions could adversely affect the safe operation of a pipeline. Such determinations would have to be made promptly but no later than 180 days after an inspection, unless the operator demonstrates that the 180-day deadline is impracticable.

Operators would be required to comply with the other provisions in Part 195 in implementing the requirements in § 195.416. These include having appropriate provisions for performing periodic assessments and any resulting repairs in an operator's procedural manual (see § 195.402); adhering to the recordkeeping provisions for inspections, tests, and repairs (see § 195.404); and taking appropriate remedial action under § 195.422. Section 195.11 would also be amended to subject regulated onshore gathering lines to the periodic assessment requirement.

Alternatives Considered

Alternative 1: No Action (Baseline—Status Quo)

Without inspection for corrosion and deformations every 10 years, threats of leaks and releases of HLs would continue for the subset of pipeline outside of HCAs that is not currently assessed and as a result would contribute to environmental damages, threats of injuries, and loss of product.

[100] Training costs are already covered under the current IM requirements.

Alternative 2: Apply All IM Program Requirements That Are Currently in Place in HCAs to Pipelines Outside HCAs
This alternative was rejected and deemed not necessary because of the lower level of risk outside of HCAs.

Other Alternatives: Longer Time Period Between Inspections or Apply the Limit Requirement to Pipeline Segments Where a Spill Could Affect a Building, Occupied Site, or Highway

PHMSA considered alternatives to its proposal that would likely have lower overall costs and benefits but potentially higher net benefits. For instance, PHMSA considered limiting the proposed expansion of certain IM requirements to those pipelines where a spill could affect a building, occupied site (such as a playground), or highway. Under this alternative, pipeline where a spill could not affect a building, occupied site, or highway would not be subject to these new requirements. However, this alternative would offer less protection to the natural environment, including sensitive and protected habitats and species. PHMSA also considered alternative assessment intervals to the proposed 10-year interval, such as a 15- or 20-year interval. However, substantial changes to pipeline integrity can occur in a short timeframe. PHMSA declined to propose these alternatives because they would provide fewer benefits than the proposed approach. More specifically, liquid spills even in remote areas can result in environmental damage, necessitating cleanup and restoration costs and lost use and nonuse values—and such spills would be likely to occur if the pipe is not assessed and repaired in accordance with this proposal. Also, a longer interval between assessments would increase risks of integrity-related failure, compared to PHMSA's proposal. PHMSA was unable to quantify the benefits and costs of these alternatives due to limitations in available information, such as the amount of unassessed pipe where a spill could not affect a building, occupied site, or highway; the environmental impact of spills from such pipe; and the incremental reduction in benefit between 10-year and alternative interval periods. PHMSA seeks public comments on these alternatives, and the regulatory impact analysis contains specific questions for public comment on quantifying these alternatives.

Analysis of Costs and Potential Benefits of the Proposed Action

Analysis of Costs
Costs include assessments of all HL pipelines not currently assessed voluntarily or for compliance with IM regulations. The proposed rule would require that these assessments be conducted at least once every 10 years. Assessments often use more than one inspection tool, device, or test to adequately assess a particular pipeline. An assessment is complete when all of the required tools, devices, or tests have successfully evaluated the pipeline. Once the inspections are complete, the operator evaluates pipeline anomalies and makes repairs as needed.

Table 12 shows the parameters and steps in the calculation for estimating the cost of the proposed requirement, followed by a discussion of these parameters and steps.

Table 12. Calculation of Annual Inspection and Repair Costs (2013 $)

Parameters and Calculations	ILI	Pressure Test
Number of Miles Assessed per Year	1637	142
Inspection Cost per Mile	$5,150	$15,000

Parameters and Calculations	ILI	Pressure Test
Inspection Costs (Millions)	$8.40	$2.10
Repairs per Mile	0.27	0.015
Cost per Repair	$13,800	$25,000
Repair Costs (Millions)	$6.10	$0.05
Total Annual Costs (Millions)	**$14.5**	**$2.2**
Total Cost per Mile	$8,857	$15,127

1. Number of Miles Assessed per Year

The first step in estimating costs is determining the number of non-HCA miles that would need to be assessed every 10 years under the proposed requirement that are not currently assessed.

Based on a survey of API members, PHMSA estimates that 17,794 miles of previously unassessed non-HCA pipeline will be subject to the proposed inspection requirement. According to the API survey results reported in 2011, operators inspected approximately 83 percent of their non-HCA pipeline at the time of the survey.[101] PHMSA estimated non-HCA pipeline miles affected by the proposed requirement by multiplying 0.17 by 104,670 total non-HCA pipeline miles in 2011.[102]

PHMSA notes that there is uncertainty regarding the extent to which repairs were performed, including a full schedule of recommended follow-up, on all identified anomalies in the non-HCA pipeline falling within the estimated 83 percent of non-HCA pipeline that is currently inspected. PHMSA believes that anomalies both inside and outside HCAs that are recognized as critical are addressed by operators when they are identified. PHMSA requests public comments on the extent this proposal would require operators to make additional repairs to pipeline this analysis assumes would be assessed in the absence of this rule.

PHMSA estimates that of the 17,794 (or 17 percent of 104,670 total non-HCA miles in 2011) miles that will be subject to inspection and repairs because of this requirement, 1,779 miles will be assessed each year in the 10-year period. PHMSA distributes the 1,779 miles of pipeline subject to assessment into testing by ILI and testing by pressure test. Due to lack of data regarding characteristics of the uninspected miles, PHMSA assumes that the assessments will be done through ILI and pressure testing in the same proportions as the pipelines that have already been assessed. Ninety-two percent of the 1,779 miles will undergo ILI testing each year (or 1637 miles of pipeline), while the

[101] Comment to PHMSA for the HL ANPRM provided by AOPL-API in a letter dated February 18, 2011. In a survey of its member pipeline companies (covering 93,867 miles), API found that through the course of assessing HCA segments and pipeline near those segments, operators had assessed 83 percent of their non-HCA mileage. When combined with HCA mileage that had been assessed, this represents 90 percent of the total mileage for the survey respondents. PHMSA has placed this comment letter in the docket for this rulemaking.

[102] PHMSA assumes that non-HCA miles added to the HL pipeline infrastructure since 2011 are already inspected for two reasons. Under current regulations, all newly constructed pipeline is required to undergo pressure testing before operating and all newly constructed pipeline is required to be piggable.

remaining 8 percent (or 142 miles of pipeline) are assumed to undergo pressure testing.[103] PHMSA requests public comments about its assumptions regarding the amount of pipe that will be assessed using various assessment tools in response to this rule.

PHMSA assumes that the costs of compliance with this requirement in the first 10 years are attributable to existing non-HCA pipeline that has not been inspected. In the first 10 years, newly constructed pipeline will not add to the cost of the proposed rule because newly constructed non-HCA and HCA pipeline are required to be pressure tested before it is permitted to operate under § 195.302. Since 1994, new and replacement HL pipeline have been required to accommodate ILI tools under §195.120. When operators inspect HCA pipeline using ILI tools, they generally continue the ILI inspection along the non-HCA pipeline as well.[104]

PHMSA requests public comments on the amount of new, non-HCA pipeline that would be assessed at least every 10 years in the absence of this rule.

2. Inspection Costs

PHMSA calculates inspection cost per mile separately for ILI and pressure tests. Based on a 2002 Corrosion Report and the Final RIA for the Pipeline Integrity Management in High Consequence Area Rule, PHMSA estimates that the inspection cost per mile for ILI testing is approximately $5,150 per mile. This estimate includes pre-inspection cleaning, the cost of the ILI tool, and the operator's labor for soliciting bids, selecting contractors, overseeing, and reporting.[105] The estimate does not include the cost of modifying unpiggable pipeline to accommodate ILI tools. Because the inspections are only required at least once every 10 years, PHMSA assumes that operators of unpiggable pipeline will choose pressure testing.

Operators who use other methods must notify PHMSA in advance of the inspection and establish that the segment of pipeline to be inspected by an alternative means cannot accommodate an ILI and that the chosen method provides sufficient information about the condition of the pipeline. As detailed above, PHMSA estimates that of the 1,779 miles that will be assessed on an annual basis, only 142 miles will be assessed using an alternative method (i.e., pressure testing). Based on this 142-mile estimate (representing 1.4 percent of non-HCA pipeline in 2011), PHMSA estimates that 10 notifications will be submitted each year. Further, PHMSA estimates that each notification will take 1 hour, which includes the time to collect the necessary details to demonstrate that the pipeline is not capable of accommodating an ILI tool and specify that the alternative assessment method will provide a substantially equivalent understanding of the pipeline. This will result in a cost of $ 414.20 ($41.42 (fully loaded salary cost) * 10 hours).

---

[103] Calculated from PHMSA Hazardous Liquid Integrity Management Performance Measurement data by dividing the total number of miles pressure tested between 2004 and 2013 by the total number of miles inspected. To access data, go to http://primis.phmsa.dot.gov/iim/perfmeasures.htm and click on "Hazardous Liquid IM Performance Metrics."

[104] Ibid.

[105] Thompson, Neil (2002). "Appendix E: Gas and Liquid Transmission Pipelines." CCTechnologies laboratory. Pp. E30–E32. Final Regulatory Evaluation for the Pipeline Integrity Management in High Consequence Areas, Docket RSPA-00-7408, p. 18. We inflated all cost estimates to 2013 dollars.

PHMSA estimates that the average cost of pressure testing is $15,000 per mile. Based on professional judgment, PHMSA estimated that the cost for pressure testing 24-inch pipe is $25,000 per mile, including water acquisition and disposal.[106] PHMSA assumes that approximately 67 percent of the pipeline that will undergo pressure testing because of this requirement is small-diameter pipeline, typically from 8 to 10 inches. Small pipe diameter is one reason that pressure testing may be used instead of ILI. Additionally, a portion of the operators transporting nonvolatile liquids and pressure testing small-diameter pipe will operate pipeline that meets the requirements that allow for pressure testing with the transported commodity instead of water and will choose to do so. PHMSA estimates that pressure testing segments with 8- to 10-inch diameter using water costs approximately $12,000 per mile, which is about half the cost of pipeline segments with a 24-inch diameter. PHMSA estimates that pressure testing with the transported nonvolatile commodity costs $8,000 per mile because there is no cost of water acquisition or disposal. Assuming that approximately one-third of pipeline is 24-inch pipe tested with water, one-third is small-diameter pipe tested with water, and that the remaining third is small-diameter pipe tested with product, PHMSA estimates an average per-mile testing cost of $15,000.

Note that in comparison, pressure testing of gas pipelines can be substantially more costly than pressure testing HL lines. There are several reasons for this cost differential. First, economies of scale in pressure testing for gas pipelines will not be realized on shorter unpiggable intrastate segments. Also, gas pipes include wider diameters and thus costs for water and disposal are higher, and some portion of HL pipelines (small-diameter pipes transporting nonvolatile liquids) can be tested with product instead of water. Another potentially large difference is the cost to establish a temporary gas supply if there is no alternate supply and demand is high. Operators would avoid pressure tests if other methods are available. However, in such infrequent instances in which there is no alternative, establishing temporary gas supplies could add $1,000,000 or more per test. Further, there is no lost product for HL pressure tests as occurs with gas pipelines, nor is there an accompanying social cost of the greenhouse gas emissions associated with gas released.

Neither the estimate for ILI testing nor the estimate for the pressure testing includes the loss of throughput during the 6 to 10 days that the pipeline is shut down for testing. The lost revenue during this time can be a significant cost to the operator, but the loss to the operator performing the test is a gain to other operators who may move the throughput instead. From a cost-benefit perspective, there is no net social loss from the loss of throughput for an individual operator, provided that the liquid will be rerouted through other pipeline. If, however, the temporary closure of a pipeline for pressure testing results in a bottleneck that significantly delays the delivery of HL product to end users, then the cost delays caused by lost throughput could be a significant cost associated with pressure testing. PHMSA seeks comment on the cost of pressure testing in general and the cost of lost throughput specifically.

[106] Based on information from vendors, PHMSA estimates the cost for testing a 10-mile segment to be $150,000 for hydroservices only, and another $100,000 for water, water disposal, isolation, chemical cleaning, and other services (not including nitrogen), for a total cost of $250,000 (or $25,000 per mile).

Total inspection costs are calculated separately for ILI and pressure testing as the product of the cost per mile inspected and the number of miles inspected.

3. Annual Excavation and Repair Costs

It is difficult to get a precise estimate of excavations and repair costs from published reports because the estimates are not always expressed per repair or per mile. PHMSA estimated $25,000 for the repair cost of cleanup and replacement following a pressure test failure based on PHMSA professional judgment. Again, in comparison, note that repair costs are likely lower than for some gas pipeline repairs. Repair costs are higher in urban and populated areas, which are more likely to contain gas pipelines compared to the areas covered by the proposed HL rule (non-HCAs only). Also, the assumption of pressure testing relates to HL pipelines that are small diameter (i.e., the reason the lines are not piggable), which reduces repair costs; material verification would also add costs for gas lines. Finally, HL repairs do not involve the cost of lost product for replacement of pipe segment.

The cost per repair is higher for pressure testing than for ILI because repairs following a pressure test involve pipe replacement due to a failure during the test. In contrast, ILI is able to identify needed repairs without causing a failure.[107] PHMSA inspection data indicate that the rate of failure in pressure tests is 0.015 failures per mile.[108]

Although this RIA applies to HL pipelines, we consider the EPA cost estimates for gas pipelines in the analysis.[109] A study conducted for EPA suggests that a wrapping of gas pipelines can be accomplished for between $5,600 and $22,000. PHMSA used the midpoint of this range of $13,800 for its estimate of the cost per repair following an ILI. There were 0.27 repairs for every mile assessed using ILI, according to PHMSA data.[110]

[107] Thompson, Neil (2002). "Appendix E: Gas and Liquid Transmission Pipelines." CCTechnologies Laboratory. Pp. E30–E32. Final Regulatory Evaluation for the Pipeline Integrity Management in High Consequence Areas, Docket RSPA-00-7408, p. 18. All cost estimates were inflated to 2013 dollars.

[108] The pressure test failure rate was calculated from answers to questions 3a and 3b in Part F of the annual report operators are required to file with PHMSA. 3a asks for the total number of miles inspected by pressure testing. 3b asks for the total number of repairs due to leaks or ruptures due to pressure testing. The repair rate per mile was calculated as the total number of leaks and ruptures due to pressure testing divided by the total number of miles inspected by pressure testing. Between 2004 and 2013, there were 798 pressure test failures from pressure testing 51,915 miles. The annual report data can be downloaded at http://phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print.

[109] There are several methods that can be used. See "Composite Wrap for Non-Leaking Pipeline Defects," http://epa.gov/gasstar/documents/ll_compwrap.pdf (accessed August 11, 2014.), or http://www.pipelinesinternational.com/news/advantages_of_steel_sleeves_over_composite_materials_for_pipeline_repair/061223/. Estimates are taken from p. 8 of the EPA reference. The lower bound estimate is based on the cost of composite wrap repair for a 6-inch defect in a gas pipeline with a 24-inch diameter. The upper bound estimate is based on pipeline replacement for a 234-inch defect in a pipe with the same specifications. For HL pipeline, replacement is more cost effective than repair for the 234-inch defect. The replacement cost estimate was adjusted to reflect the fact that unlike gas pipelines in which a significant amount of product must be vented during the replacement process, replacement of HL pipeline does not require a significant product loss.

[110] The excavation and repair rate for ILI data was calculated from answers to questions 1e and 2a and b in Part F of the annual report that operators are required to submit to PHMSA. The rate is calculated as repairs and excavations divided by total number of miles assessed by ILI. The annual report data can be downloaded at

Excavation and repair costs were calculated separately for ILI and pressure testing as the number of repair conditions per mile times the number of miles inspected times the cost per excavation and repair.

4. Total Costs

Total annual assessment costs are $16.7 million each year, the sum of annual inspection and repair costs for ILI pipes ($14.5 million) and inspection and repair costs for pressure tests ($2.2 million). At 3-percent and 7-percent discount rates, the present value of costs from all 10 years of assessment are $146.3 million and $125.1 million, respectively.

Analysis of Benefits

PHMSA assumes that assessments in any 1 year provide benefits over the 10-year period between assessments. Therefore, PHMSA compares the 1-year upfront costs to the present value of benefits accrued over a 10-year period. The benefits in the 10 years following an assessment are calculated as the number of Incidents Avoided times the Social Losses per Incident. Table 13 shows the calculation of the number of incidents avoided over 10 years, followed by a discussion of the steps and parameters for the calculation.

Table 13. Calculation of Number of Incidents Avoided Over 10 Years

Test	Repairs per Mile	Miles	Total Repairs From Each Year's Assessments	Probability That Repair Prevents Incident	Total Incidents Avoided Over 10 Years	Social Losses Avoided per Incident
ILI	0.27	1637.0	442.0	0.1	44.2	$498,291
Pressure	0.015	142.4	2.1	1	2.1	$498,291

1. Total Repairs From Each Year's Assessments

In Table 13, the estimate of total incidents avoided over 10 years is the product of the Total Repairs From Each Year's Assessment and the Probability That Repair Prevents Incident. The Total Repairs From Each Year's Assessment is calculated as the product of Repairs per Mile and the Miles Assessed based on PHMSA annual report data, which is calculated in Table 12.[111]

http://phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print. The rate of pressure test failures is calculated from PHMSA performance metrics data regarding pressure testing. Between 2004 and 2013, there were 798 pressure test failures over a total of 51,915 miles pressure tested.

[111] PHMSA annual report data is downloadable in Excel files at the following site: http://phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print. The data are available under the "Hazardous Liquid Annual Data 2010 to Present" tab on the right side of the page. The data used in this NPRM were downloaded on December 11, 2014. Repairs per mile were calculated as the number of repairs divided by the number of miles inspected for each inspection type.

2. Probability That Repair Prevents Incident

   In Table 13, the Probability That Repair Prevents Incident in the following 10 years is 0.10 for ILI assessments and 1 for pressure test assessments. PHMSA does not have any specific data on the probability that a repair following an ILI assessment will prevent an incident: in incident reports, respondents fail to indicate whether or not an inspection had been previously conducted on that pipeline nearly a third of the time, and in annual reports, operators indicate whether they had inspections on pipeline but do not specify the precise locations of the inspected pipeline. Therefore, there is no reliable empirical way to correlate the relationship between incidents at specific points along pipeline and inspections of that pipeline based on past occurrences.

   As a result, the Probability That Repair Prevents Incident is derived from the distribution of repair types following an ILI inspection along HCA pipeline and from the assumed probabilities that each type of inspection prevents an incident. According to operator annual reports, approximately 18 percent of post-ILI repairs are classified as immediate, 16 percent are classified as 60-day repairs, and 67 percent are in the 180-day category. PHMSA assumes that immediate repairs are more likely to result in incidents averted because the repairs are responding to defects that meet immediate repair criteria. Defects meeting this criteria are less likely to be identified at scheduled (e.g., 60-day or 180-day) repairs, which occur more frequently. Thus, for the purposes of this analysis, PHMSA assumes that the probability of an immediate-repair anomaly causing a failure in the next 10 years if not repaired is 0.25, the probability of a 60-day repair causing an incident within 10 years if not repaired is 0.125, and the probability of a 180-day repair causing an incident in the next 10 years if not repaired is 0.05. These assumed probabilities imply that the average probability that a repair following ILI inspection prevents a loss is approximately 0.10 (0.18 * 0.25 + 0.16 * 0.125 + 0.67 * 0.05). For simplicity, we conservatively estimate that the prevented losses from ILI repairs are spread evenly over 10 years. PHMSA requests information regarding the probability that a repair will prevent a loss within 10 years.

   For the purposes of demonstrating a range of outcomes, since specific data on the probability of the prevention of an ILI incident as a result of repair is unknown, PHMSA is also calculating low and high case probabilities to reflect the possibilities that chances of repair following inspection are lower or higher than the base 0.10 assumption. For the low estimate of the probability that ILI incidents are prevented as the result of repair, PHMSA applies a factor of 0.5 to the base probabilities, and for the high estimate, PHMSA applies a factor of 1.5 to the base probabilities.

   In the absence of specific data, PHMSA assumes that every pressure test failure avoids an incident in the first year after the test with a probability of 1. PHMSA assumes this high probability for pressure tests because pressure tests result in actual leaks or ruptures during the test.

Table 14 shows calculations of Total Incidents Avoided considering the high (0.15), base (0.10), and low (0.05) case scenarios of the probability that an ILI repair prevents an incident from occurring.

Table 14. Number of Incidents Avoided Over 10 Years From Year 1 Inspection Based on Low, Base, and High Probabilities That Repair Prevents Incident

Case	Total Repairs from Year 1 Assessments	Probability That ILI Repair Prevents Incident	Total ILI Incidents Avoided	Total Pressure Test Incidents Avoided	Total Incidents Avoided
Low	444.1	0.05	22.1	2.1	24.2
Base	444.1	0.10	44.2	2.1	46.3
High	444.1	0.15	66.3	2.1	68.4

As Table 14 shows, the Total Incidents Avoided over 10 years from the first year's assessments varies, with 24.2 in the low scenario, 46.3 in the base scenario, and 68.4 in the high scenario.

PHMSA evaluated benefits based on the assumption that 10 percent of the currently uninspected pipeline will be inspected every year. In the tenth year, the entire uninspected pipeline will have been inspected once. PHMSA assumed that the total number of incidents prevented by each round of inspections will take 10 years from the date of inspection to be fully realized. Therefore, the benefits of the inspections in the final 10 percent of pipeline inspected will not be fully realized until 19 years after the enactment of the proposal. After accounting for the timing of the benefits, the average annual number of incidents prevented over the 19 years that benefits accrue is expected to be 24.4 incidents per year at the baseline probability of 0.10, 12.8 incidents per year at the 0.05 lower-bound estimate, and 36.0 at the 0.15 upper-bound probability estimate. From 2010 through 2014, the annual rate of potentially ILI-preventable incidents averaged 47.6 incidents per year on non-HCA pipeline. Therefore, the analysis estimates that, on average, repairing the anomalies found from assessing the 17 percent of non-HCA pipeline that is not currently being assessed would have prevented about half of the annual incidents on all non-HCA pipe that were potentially preventable by assessments.

Table 15 presents the calculations for the benefits from Incidents Avoided due to the repairs that take place after the assessments in the first year. The benefit stream over 10 years is presented in undiscounted dollars and discounted using rates of 3 percent and 7 percent. The Total row at the bottom of Table 15 presents the total present value of the benefit stream over 10 years in undiscounted dollars and using discount rates of 3 percent and 7 percent.

Table 15. Benefits Stream From Year 1 Assessments and Associated Repairs (Millions of 2014 $)

Benefits Stream From Year 1 Assessments	Incidents Avoided	Social Cost Savings per Incident in Non-HCA (Millions of 2013 $)	Undiscounted Social Cost Savings	Discount Rate 3%	Discount Rate 7%
1	6.60	$0.5	$3.30	$3.30	$3.3
2	4.42	$0.5	$2.21	$2.15	$2.1
3	4.42	$0.5	$2.21	$2.08	$1.9
4	4.42	$0.5	$2.21	$2.02	$1.8
5	4.42	$0.5	$2.21	$1.96	$1.7

Benefits Stream From Year 1 Assessments	Incidents Avoided	Social Cost Savings per Incident in Non-HCA (Millions of 2013 $)	Undiscounted Social Cost Savings	Discount Rate 3%	Discount Rate 7%
6	4.42	$0.5	$2.21	$1.91	$1.6
7	4.42	$0.5	$2.21	$1.85	$1.5
8	4.42	$0.5	$2.21	$1.80	$1.4
9	4.42	$0.5	$2.21	$1.74	$1.3
10	4.42	$0.5	$2.21	$1.69	$1.2
		Total	**$23.2**	**$20.5**	**$17.7**

Table 15 shows the calculation of total quantified benefits from Year 1 assessments. The Undiscounted Social Costs Savings from Year 1 inspections and repairs is calculated as the product of the Incidents Avoided and the Social Cost Savings per Incident. These social cost savings are then summed over each of the 10 years that it takes for benefits from 1 year of inspections to be fully realized.

1. Incidents Avoided Due to Repairs Completed in Year 1

   In Year 1, the Incidents Avoided is 6.5, reflecting the total of incidents avoided by ILI testing (4.4) and pressure testing (2.1) in the first year following the repairs. In Years 2 through 10, there are 4.4 incidents avoided every year due to the repairs from ILI assessments completed in Year 1.

2. Benefits per Incident Avoided

   Benefits per Incident Avoided is calculated using PHMSA accident data.[112] PHMSA identified 238 reportable incidents on non-HCA segments that occurred between 2010 and 2013, with causes indicating they potentially could have been prevented by an ILI assessment. PHMSA limited the incidents used to calculate average loss per incident to all non-HCA incidents that were potentially preventable by ILI.[113] The 238 incidents included in the analysis all involved pipe or weld and one of the following causes: internal and external corrosion; previous damage due to third-party excavation; and material, weld, or equipment failure. According to PHMSA incident reports, the 238

[112] The incident and cost data were downloaded from http://www.phmsa.dot.gov/pipeline/library/datastatistics/flagged-data-files on June 30, 2015. To calculate social costs in this RIA, PHMSA used the total cost variable that PHMSA converted to 2014 dollars and adjusted for changes in commodity prices. For the single corrosion incident in this time period that resulted in a fatality and injury, PHMSA used the DOT VSL and injury severity scales.

[113] Incidents must be reported (under 195.50) if the incident caused a death or injury requiring hospitalization, resulted in an unintentional fire or explosion, caused more than $50,000 in property damages, or the release is greater than 5 gallons. However, releases that are more than 5 gallons but less than 50 barrels that result from pipeline maintenance are not required to be reported under this rule if they do not pollute any waterway, are confined to company property or ROW, are cleaned up promptly, and do not meet any of the other reporting thresholds. For more detail on regulatory reporting requirements, see https://www.law.cornell.edu/cfr/text/49/195.52 and https://hip.phmsa.dot.gov/Hip_Help/pdmpublic_incident_page_allrpt.pdf.

incidents had social costs totaling $118 million, for a cost per incident of $0.498 million and 10 million gallons of lost product. Appendix A presents a full list of these incidents.

Table 16 presents benefits in the form of total social cost savings from assessments performed in Years 1 through 10.

Table 16. Benefits Stream, Years 1–10 (Millions of 2014 $)

Year	Undiscounted Benefits	Discount Rate 3%	Discount Rate 7%
1	$23.2	$20.5	$17.7
2	$23.2	$19.9	$16.5
3	$23.2	$19.3	$15.5
4	$23.2	$18.8	$14.4
5	$23.2	$18.2	$13.5
6	$23.2	$17.7	$12.6
7	$23.2	$17.2	$11.8
8	$23.2	$16.7	$11.0
9	$23.2	$16.2	$10.3
10	$23.2	$15.7	$9.6
Total	**$231.7**	**$180.0**	**$132.8**

Table 16 shows that the total undiscounted social cost savings are $231.7 million from inspections completed in the first 10 years of the proposed requirement. At 3 percent and 7 percent discount rates, the social cost savings are $180.0 million and $132.8 million, respectively. Each entry in the table is the present value of the 10-year stream of benefits attributable to the 1,779 miles of pipeline assessed that year. For example, the cell for Year 2 under the 3-percent discount rate column equals the present value of the 10-year stream of benefits for Year 1 discounted back 1 additional year to reflect the later timing of the inspection and ensuing benefits.

Quantified Net Benefits

Table 17 presents the total quantified costs and benefits of the requirement over 10 years. The undiscounted 10-year total net benefits are $65.2 million. At a 7-percent discount rate, the 10-year total quantified net benefits are $7.7 million.

Table 17. Total 10-Year and Annualized Benefits and Costs (Millions of 2014 $)

	10-Year Totals (Millions of 2013 $)			Annual (Millions of 2013 $)		
	0%	3%	7%	0%	3%	7%
Benefits	$231.7	$180.0	$132.8	$23.2	$20.5	$17.7
Costs	$166.5	$146.3	$125.1	$16.7	$16.7	$16.7
Net Benefits	**$65.2**	**$33.7**	**$7.7**	**$6.5**	**$3.8**	**$1.0**

Sensitivity Analysis

Table 18. Annualized Net Benefits (Millions of 2014 $)

Probability That Repair Prevents Incident	Annualized Net Benefits		
	0%	3%	7%
0.05	($4.5)	($54.9)	($76.3)
0.1	$7.5	$4.9	$2.0
0.15	**$17.6**	**$13.5**	**$9.3**

One of the goals of this NPRM is to solicit public comments for information regarding the cost and benefit parameters. One of the most uncertain parameters is the percentage of repairs that prevent incidents. Table 18 shows that net benefits depend critically on the assumptions about this parameter. For a plausible range of estimates for this parameter, quantified net benefits can be positive or negative but are positive for the midrange case.

Although the 0.15 probability that a repair prevents an incident theoretically implies that the average annual rate of 34 incidents prevented over the next 19 years due to inspections completed in the first 10 years is 70 percent of the historical average annual potentially ILI-preventable incident rate of 48 for all non-HCA pipeline from 2010 through 2014, PHMSA believes the high end of the range is plausible. Given that threats to the integrity of pipelines—such as corrosion—rise over time, and considering also the aging of pipeline and the increasing volume of material moving through pipelines, PHMSA expects that incident rates on non-HCA pipeline would rise in the future without this requirement. Corrosion damage accumulates over time. If nothing is done to inspect and repair aging pipeline, annual incident rates would be expected to increase. As of 2013, approximately 50 percent of all HL pipeline was over 43 years old, (built before 1970).[114]

Another factor that contributes to an expected increase in incident rates absent the proposed inspection requirement is the increase in ton-miles of HLs, especially crude oil, that the pipeline infrastructure is expected to transport. For example, according to one forecast, the total ton-miles of transported crude oil is expected to increase 75 percent from 2012 levels by 2025.[115] Additional pipeline miles are planned to be added to the infrastructure over this time period. However, because of the length of time it takes to construct new pipeline, the current infrastructure is likely to be operating at or near its maximum capacity until construction of pipeline catches up with demand.

Additional Unquantified Benefits

Because the quantified net benefits are negative over some of the range bounded by the low and high estimates in the sensitivity analysis, PHMSA believes that it is necessary to consider

[114] Adopted from PHMSA pipeline inventory. See https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?PortalPages (accessed January 2, 2015). The data were not available separately for HCA and non-HCA pipeline. Furthermore, because of the way pipeline HCA mileage and age mileage are reported, it is not possible to derive separate HCA and non-HCA pipeline age statistics. The pipeline age data is presented in Table 16 of this RIA under Requirement 7.

[115] From the Freight Analysis Tabulation Data Tabulation Tool at http://faf.ornl.gov/fafweb/Extraction1.aspx. The site is maintained by the Center for Transportation Analysis.

benefits not captured in the quantified analysis for this requirement. Some of the unquantified benefits most relevant to this requirement include the following:

- ***Underreported Damages:*** Particularly in cases where the incident report indicates that there was environmental contamination and yet no environmental costs were recorded, it is possible that there are costs unaccounted for in the incident report that lead to the social cost savings per incident calculation not reflecting a full capture of all costs. Furthermore, some significant costs such as litigation costs are specifically excluded from reported damages.
- ***Environmental and Health Externalities:*** Additionally, there are various areas of benefits from the implementation of this rule that are difficult or costly to monetize but may be substantial, including externalities associated with personal health and the environment. Moreover, it may take years to assess the full impact of the environmental damages. For a more detailed discussion of these benefits, see Section 2.6.2 of this RIA.
- ***Increased Situational Awareness:*** Although this analysis is limited to incidents involving pipe and weld failures, the process of preparing for and conducting an inspection leads to greater situational awareness and information integration that may reduce the likelihood of incidents involving other parts or from other causes.

Interaction With Other Proposed Requirements

This requirement is not expected to interact significantly with any of the other requirements in terms of the net benefits. It only applies to the 14 percent of non-HCA pipeline that has not been assessed. This requirement and the other internal inspection requirements do not protect against the same types of hazards as the 72-hour post-disaster inspection rule.

Request for Comments

PHMSA requests comments on the following:

1. PHMSA requests per-mile cost estimates for pressure testing, broken down by the major cost components such as water handling and disposal of wastewater, repair and replacement of damaged pipe, preparation of the pipeline, and cost of lost throughput.
2. Is HL rerouted through other pipeline without significant delay during pressure testing, or does the temporary closure of a segment of pipeline for pressure testing cause bottlenecks that delay HL commodities from reaching end users? If the latter, how can PHMSA estimate such costs?
3. PHMSA requests estimates of the cost of repairing or replacing pipe and cleanup after a pressure test failure.
4. PHMSA requests data on the per-mile component cost of ILI inspection.
5. PHMSA requests comments on the effectiveness of ILI and pressure testing assessments.
6. What are the failure probabilities for corrosion and deformation defects discovered through ILI or pressure testing if the defects are not repaired?
7. Do pipelines in non-HCA areas that have not been assessed pass through areas with lower population density, less property, and less environmentally sensitive areas than pipelines in non-HCA areas that have already been assessed?
8. Do pipelines in non-HCA areas that have not been assessed require a greater portion of hydrostatic testing or direct assessment than pipelines in non-HCA areas that have already been assessed? Are there any other additional costs that would be incurred from assessing and repairing the pipeline affected by this proposal relative to pipeline that would be assessed and repaired in the absence of this proposal?
9. Does the composition of pipeline infrastructure that has not been assessed differ from non-HCA pipeline that has been inspected in terms of characteristics that affect pressure testing costs such as pipe diameter, pipe age, and location?
10. For what percentage of pressure tests does the operator use the non-highly volatile commodity in the pipe instead of water to conduct the test?
11. PHMSA does not have information on the number or costs of incidents that occurred on pipeline not previously assessed. PHMSA estimates that about 24 incidents will be prevented each year from assessing and repairing the 17,794 miles of pipeline estimated to be affected by this proposal and that the average incident on such mileage costs about $500,000. Is the number of incidents expected to be prevented by this proposal and the estimated average cost of such incidents reasonable? Are there other information sources available that could be used to refine these estimates?
12. The benefit and cost estimates for this proposal assume operators will, in the absence of this rule, make all repairs required by this proposal to non-HCA pipeline they previously assessed. Is this assumption correct? If not, what information is available for estimating the impact of additional repairs on non-HCA pipe?

Requirement Area #5 – Require LDSs for All HL Pipelines

The Target Problem and Need for the Proposed Action

Proposed Action: PHMSA is proposing to amend § 195.134 to require that all HL pipelines be designed to include LDSs. Since pipelines that could affect HCAs are already mandated to have an LDS, this provision would extend to pipelines outside areas that could affect HCAs.

Alternatives Considered

Alternative 1: No Action (Baseline—Status Quo)

Under this option, PHMSA's safety mission would be compromised. By not taking action on leak detection, the Agency would be unresponsive to Congressional mandates and there would likely be inefficiencies and gaps in pipeline safety. Although taking no action would eliminate additional compliance costs, there would be no benefits ensuing.

Alternative 2: Require All Pipelines to Maintain an LDS

PHMSA considered proposing to amend § 195.444 to require that operators have a means for detecting leaks on all portions of an HL pipeline system and to require that an evaluation be performed to determine what kinds of systems must be installed to adequately protect the public, property, and the environment. The factors that had to be considered in performing that evaluation would include the characteristics and history of the affected pipeline, the capabilities of the available LDS, and the location of emergency response personnel. A proposed amendment to §195.11 would have extended these new leak detection requirements to all regulated onshore gathering lines, regardless of whether they were existing or new.

Alternative 3: Provide Prescriptive Federal Regulation

Specifying in detail actions that must be taken was deemed to be too inflexible by PHMSA. PHMSA had convened a group to study a similar action for DIMP. The study group reasoned that a highly detailed prescriptive regulation would eliminate the flexibility needed to address the unique circumstances of individual States and operators. In addition, some operators need the flexibility to address the issues under their purview depending on the siting of the pipeline and the technology available to address the problem.

Baseline

The authors of the 2012 Leak Detection Study defined an LDS as "any technology or method that can be employed by a pipeline operator to detect the loss of fluid from a pipeline or its associated fittings."[116] This proposal requires leak detection on all HL pipelines. Currently, all HL pipeline that could affect an HCA are explicitly required to have an LDS under 195.452 and are therefore not affected by this proposed requirement. Alaska regulations implemented in 1997 also require an LDS with the ability to detect leaks as small as 1 percent of flow in all HL pipelines wherever the 1-percent sensitivity requirement is technologically feasible.

[116] U.S. DOT PHMSA (2012). Final Report, Leak Detection Study—DTPH56-11-D-000001, prepared by Kiefner and Associates.

Additionally, some pipelines that cross the Canadian border into the United States are subject to Canadian regulations requiring an LDS.[117]

There are many types of LDSs. PHMSA IM regulations do not prescribe a specific leak detection technology, nor does the proposed requirement. Control room procedures and protocols for monitoring, evaluating, and responding to SCADA pressure and flow changes that indicate a potential release may be an acceptable LDS for some pipelines. SCADA systems collect data from sensors in real time and display this information to human operators who monitor the data and operate the pipeline from remote sites.[118] Nearly all operators use SCADA systems to monitor and manage normal pipeline operations. The most common type of LDS relies on a SCADA system coupled with Computational Pipeline Monitoring (CPM), a software program that applies an algorithm to pressure/flow monitoring sensors inside a pipeline to determine if conditions are consistent with a release. When conditions inside the pipe are consistent with a leak or rupture, the system sounds an alarm. The control room operator must then determine whether the alarm indicates a true release and take appropriate actions. Although PHMSA regulations do not currently mandate pipeline operators to use a CPM, any pipeline system (HCA and non-HCA) with a CPM must comply with the API 1130 recommendations regarding design and operation of a CPM system under FR 195.444. Under FR 195.134, the design of an LDS in any new pipeline system (HCA and non-HCA) that includes a CPM must also comply with API 1130.

Although HL pipelines outside of areas that could affect HCAs are not explicitly required to have a CPM, operators with a CPM usually employ it across the entire pipeline system for both HCA and non-HCA miles.[119] The CPM software is a fixed cost that does not change significantly according to the length of the pipeline. It is likely to be less difficult for control room operators to interpret alarms and manage the pipeline with one LDS system rather than separate systems for HCA and non-HCA segments.[120] Pressure/flow sensors are generally already present across the entire length of the pipeline, inside and outside HCAs, for the operation of the SCADA system. PHMSA requests public comments on the extent to which pressure and flow sensors would need to be added in response to this rule and the cost. The additional cost of extending CPM capabilities to non-HCA miles is minimal for systems already equipped with the required SCADA sensors. According to API and AOPL, "most operators already perform leak detection capability evaluations across the entire pipeline system and not just those areas subject to the HCA requirements….There is no distinction between HCA and non-HCA portions of a segment with typical CPM systems."[121] Although the proposal to mandate an LDS on non-HCA pipeline does not require a CPM system, operators who choose to use a SCADA-based system without a

[117] U.S. DOT PHMSA (2012). Final Report, Leak Detection Study—DTPH56-11-D-000001, prepared by Kiefner and Associates.
[118] National Transportation Safety Board (2006). *Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines.* Safety Study NTSB/SS-05/02.
[119] API and AOPL concurred with this conclusion in their February 18, 2011, comment to the ANPRM. Both organizations expressed support for extending leak detection capability evaluations to all pipelines regulated under Part 195, except rural gathering lines.
[120] PHMSA 2011-0177. Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, Federal Register, Volume 76, No 144, July 27, 2011, Notices.
[121] API and AOPL in their February 8, 2011, comment to the ANPRM.

CPM would also design the LDS to cover the entire pipeline and not just HCA segments for the same reasons. Because of the operational benefits of a SCADA system and the associated sensors, it would be unusual for a new pipeline not to be built with at minimum a SCADA-based LDS.[122]

In the 2012 Leak Detection Study, Kiefner and Associates interviewed engineers and operators at nine HL pipelines to assess current industry practices. All nine of the HL operators used pressure/flow monitoring as part of an LDS, while eight of the nine HL operators also used a volume balance CPM for leak detection. The operators of the pipeline without the volume balance CPM had plans to install a volume balance CPM. Because the SCADA sensors used by a CPM are usually required for efficient HL pipeline operation, it is unlikely that new pipeline will be constructed without an LDS.

In summary, PHMSA assumes that this proposed requirement would impose minimal costs and produce minimal benefits above and beyond the status quo because it is assumed that all operators with HL pipeline in non-HCAs already have an LDS on their non-HCA HL pipeline, or could expand their LDS to non-HCA pipeline with only minimal cost. PHMSA also assumes that this proposal would not result in new repair costs because it is assumed that operators are already performing all repairs identified by an LDS. PHMSA requests public comments on these assumptions.

However, while it may already be a long-standing practice that operators have LDS technology and that they perform repairs on their LDSs, there is still a qualitative benefit to be gained from moving this long-standing practice into rule, as would be accomplished by implementation of the proposed requirement. Standards in place due to Federal requirement are more certain to be followed and convert into public safety benefits than standards in place due to practice that are not binding and could therefore be changed by HL operators with no legal repercussions.[123] PHMSA also believes there are unquantifiable benefits to both the public and operators from codifying existing practices into Federal regulation in order to provide information about the requirements, ensure compliance, and provide PHMSA with a foundation for enforcement efforts.[124]

PHMSA requests comments on these assumptions. If PHMSA's assumptions are incorrect, how much non-HCA pipeline mileage would require LDSs in order to meet this requirement, and what is the cost per mile of extending LDSs to cover this pipeline?

---

[122] Leak Detection Study – DTPH56-11-D-Kiefner & Associates, Inc. See http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_4A77C7A89CAA18E285898295888E3DB9C5924400/filename/Leak%20Detection%20Study.pdf, pages 6–12.

[123] The Washington State Department of Ecology makes a similar argument about qualitative benefits from regulations that occur even in the situation where practice or "long-standing guidance" has so far produced results, which the proposed rules would enforce. Washington State Department of Ecology Spill Prevention, Preparedness and Response Program, WAC 173-182 Oil Spill Contingency Plan Rule, Preliminary Cost Benefit Analysis (CBA), June 7, 2006, p. 9.

[124] API, Comments on PHMSA's ANPRM on Hazardous Liquids Pipeline Safety, February 18, 2011.

Requirement Area #6 – Modify the Repair Requirements for HCA and Non-HCA Pipeline

Proposed Action: PHMSA is proposing to modify the repair schedule in 195.452 (h) for HCA pipeline segments and to add a repair schedule to 195.422 for non-HCA pipeline segments.

<u>HCA Pipeline Segments:</u>
195.452 currently defines the following three categories of conditions that determine the required repair schedule:

1. Immediate Repair Conditions – Any one of the conditions specified in this category requires an operator to reduce operating pressure or shut down the pipeline until the repair is completed.
2. 60-day conditions must be evaluated and remediated within 60 days of discovery
3. 180-day conditions must be evaluated and remediated within 180 days of discovery

The proposal for HCA segments would:

- Consolidate the 60-day and 180-day repair categories into a single 270-day category.
- Add the following two conditions to the Immediate Repair Category:
    - Bottom-side dents with stress risers.
    - Defects for which the calculated burst pressure is less than 1.1 maximum operating pressure.

<u>Non-HCA Pipeline Segments:</u>
195.401 (b) (1) requires operators to correct adverse conditions on pipeline outside of an HCA “within a reasonable time.” If the condition creates an “immediate hazard,” the operator must shut down the segment until the repairs are complete.

This proposal would add specificity to these requirements by amending 195.422 to:

- Apply the immediate repair category in 195.452 (i) to non-HCA pipeline.[125]
- Establish an 18-month repair category for non-HCA pipeline.

[125] From 195.452(i), an operator must treat the following conditions as immediate repair conditions:
(A) Metal loss greater than 80 percent of nominal wall regardless of dimensions.
(B) A calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly.
(C) A dent located on the top of the pipeline (above the 4 and 8 o’clock positions) that has any indication of metal loss, cracking, or a stress riser.
(D) A dent located on the top of the pipeline (above the 4 and 8 o’clock positions) with a depth greater than 6 percent of the nominal pipe diameter.
(E) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

Alternatives Considered

Alternative 1: No Action (Baseline—Status Quo)

Under this option, PHMSA's safety mission would be compromised. Electing not to modify the pipeline repair provisions would likely result in inefficiencies and gaps in pipeline safety. Repairing pipelines in a timely manner is likely to reduce the risk to the environment and public.

Alternative 2: Refine the Repair Schedule by Adding More Risk-Based Categories for Specific Anomalous Conditions Discovered Inside and Outside of HCAs

Although the goal of this approach would be to more precisely target repair efforts according to risk, this approach could have unintended consequences. The difficulty is that many of the factors that determine risk interact with and are specific to the circumstances of the particular pipe segment in need of repair. Too many repair categories would limit the ability of the operator to prioritize repairs based on the combinations of risk factors unique to the operator's situation. PHMSA rejected this approach in favor of fewer and broader risk categories that require the operator to make immediate repairs for the conditions that are an imminent threat to pipeline integrity under any circumstance, while allowing the operator to prioritize less urgent repairs based on the operator's unique combination of risk factors.

Alternative 3: Apply IM Repair Criteria to Anomalous Conditions Discovered Outside of HCAs

In response to the NPRM, API and AOPL recommended PHMSA "apply requirements for immediate repair of certain conditions on HCA segments to the same conditions on non-HCA segments, when identified as the result of an integrity assessment."[126] PHMSA rejected this alternative, since the risk outside of HCAs is not as great as the risk inside of HCAs; PHMSA decided that an extended timeframe for making repairs outside of HCAs would be sufficient.

Analysis of Costs and Benefits of the Proposed Action

There are not expected to be significant costs or benefits related to this proposed requirement, given the level of inspections that are currently being made by operators. First, PHMSA's proposal matches the industry's suggested changes. Second, according to PHMSA and industry data, operators made approximately twice as many non-required IM repairs and repairs outside of HCAs than in IM-required repairs inside of HCAs under the same constraints. According to API and AOPL, "liquids pipeline operators inspect far more miles of pipe than are required under PHMSA regulations. A 2010 survey of certain HL pipeline operators showed that 90 percent of their pipeline miles—not just the required 44 percent designated as 'could affect' HCA mileage—had been inspected. Moreover, liquids pipeline operators reports show that, during 2010 alone, operators inspected almost as many miles in a single year as pipe miles that have been designated as 'could affect' an HCA, a classification that requires inspections and repairs on intervals not to exceed *five* years."[127] Threats outside of HCAs are guided in general by 49 CFR 195.401(b)(1), which states that if an operator discovers a threat to a pipeline, the operator must correct the condition within a reasonable time, and if the condition presents an immediate hazard, the operator must shut down the system until the condition is corrected. HL

[126] See http://www.aopl.org/publications/?fa=regulatory (accessed July 23, 2012).
[127] See http://www.aopl.org/pdf/AOPL-API_letter_on_additional_PHMSA_actions.pdf (accessed July 23, 2012), page 4.

operators are also required to have a spill plan, which PHMSA reviews and approves.[128] PHMSA seeks comments on this analysis.

Interaction With Other Proposed Requirements

This requirement is expected to enhance the effects of requirements 4 and 7 by ensuring that the results of the internal inspections are used effectively and that the identified anomalies are prioritized according to risk.

Request for Comments

PHMSA requests comments on the following:

1. When do operators typically make repairs along non-HCA pipeline now?
2. Are operators able to complete the required repairs under the specified timeline?

[128] Additional information on the repairs and remediation can be found at http://primis.phmsa.dot.gov/comm/PipelineLibrary.htm (accessed August 15, 2012).

Requirement Area #7 – Increase the Use of ILI Tools in HCAs

Proposed Action: PHMSA is proposing to require that all HL pipelines in areas that could affect an HCA be made capable of accommodating ILI tools within 20 years, unless the basic construction of a pipeline will not accommodate the passage of such a device. Short sections of pipe such as manifolds, station piping, tank farm piping, smaller lines, and other lines that ILI tools cannot go through due to their design or configuration—such as low-pressure lines, telescoping lines, sharp bends, main-line valves that are not full opening—will not be required to accommodate ILI tools. PHMSA is also proposing that after the 20-year deadline, HL pipeline that could affect a newly identified HCA be made piggable within 5 years of the HCA designation. Implementation of this proposed requirement will result in the replacement of pressure testing methods currently in use by unpiggable pipeline with ILI tools unless there are exceptions that make it impossible to accommodate ILI tools.

Regulatory Baseline: The current requirements for the passage of ILI devices in HL pipelines are prescribed in § 195.120, which since 1994, has required that new pipeline and line sections where new pipe, valves, fittings or other components are replaced be designed to accommodate ILI tools. The piggability requirement for new construction applies whether the new or replacement segment of pipeline could affect an HCA or not. There are exceptions for certain short sections of pipe or other lines with a basic configuration that is incompatible with ILI tools. The proposed requirement in this NPRM retains those exceptions and will generally not affect pipeline miles constructed after 1994 or new or replacement pipeline going forward.

PHMSA assumes that operators who own unpiggable pipeline that could affect HCAs will schedule compliance with requirements to coincide with the 20-year deadline. The costs of this proposed requirement would be borne by operators who would not have voluntarily retrofitted their pipelines and would accrue in the time period prior to the deadline when operators would retrofit their pipelines in order to meet the 20-year deadline. Operators who retrofit their remaining unpiggable pipeline prior to the 20-year deadline would be doing so voluntarily for business or operational reasons. For example, to avoid the expense of replacing aging pipeline infrastructure, some operators may voluntarily retrofit older pipelines to accommodate ILIs in order to extend the life of a pipeline beyond its original designed lifespan. Additionally, as ILI technology continues to advance, pipeline previously considered unpiggable may become piggable.

Baseline Piggability of HL Pipeline That Could Affect HCAs: The quantifiable costs and benefits of the proposed requirement depend on the number of miles of unpiggable pipeline in service 20 years from the effective date of the proposed rule. These quantifiable costs and benefits are likely to be low because 20 years from the effective date, a substantial portion of unpiggable pipeline will likely have been replaced, decommissioned due to age, or voluntarily retrofitted for piggability.

Beginning in the 1950s, new pipeline was constructed to accommodate operational pigging. The first smart pigs were introduced in the 1960s, and by the 1970s most new pipeline construction accommodated smart pigs. Table 19 shows the distribution of current PHMSA HL pipeline miles by decade installed. As of 2013, about one-half of all pipeline miles were installed before 1970. If the requirement for all HCA pipeline miles to be piggable takes effect 20 years from now in 2035, any surviving pre-1970 pipeline will be over 65 years old. At that point, operators will decide whether to retrofit any remaining unpiggable pipeline to accommodate ILIs or replace or deactivate the pipeline.

Table 19. Age Distribution of HL Pipeline Miles by Decade Constructed[129] [130]

Calendar Year	Percent Pre-1950	Percent Pre-1970	Pre-1970	1970–1979	1980–1989	1990–1999	2000–2009	2010–2019	Total Miles
2005	17	59	99,197.73	27,468.01	16,990.63	18,095.63	5,013.45		166,765.45
2006	16	58	96,062.11	28,889.86	17,384.29	17,734.80	6,647.81		166,718.88
2007	15	56	95,482.22	28,570.00	18,126.93	18,839.30	8,827.68		169,846.13
2008	15	56	97,580.71	29,302.99	17,921.39	18,360.49	10,623.49		173,789.06
2009	16	56	98,870.09	27,480.69	17,027.30	18,613.62	13,973.78		175,965.48
2010	15	52	95,218.77	30,818.69	18,120.56	18,380.74	17,521.58	1,913.61	181,973.95
2011	16	53	97,304.70	30,315.71	17,183.18	19,261.59	16,915.13	2,587.47	183,567.78
2012	15	52	97,417.35	29,991.11	17,238.21	19,083.02	17,008.88	5,470.48	186,209.04
2013	14	50	97,048.75	30,173.47	17,288.96	19,332.78	17,112.55	11,431.49	192,388.00

Even as far back as 2002, an estimated 85 percent of HL pipeline was piggable, or only 15 percent was unpiggable.[131] About 94.5 percent of HCA miles assessed in 2013 was piggable and evaluated using one or more ILI tools or ILI tools in combination with hydrotesting, external corrosion, direct assessment, or other methods.[132] The remaining 5.5 percent of HCA miles were assessed using hydrotesting or other methods without any ILI tools. Given that pressure testing requires shutting down the pipeline segment being tested and that the operational costs of pressure testing are higher than the costs of running an ILI inspection along piggable pipe, the result suggests that only about 5.5 percent of pipeline mileage that could affect HCAs was unpiggable in 2013.

The proposed requirement will retain the technical exceptions for segments of pipe with basic design requirements that are incompatible with pigging. Some portion of the 5.5 percent of

[129] Adopted from PHMSA pipeline inventory https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?PortalPages (accessed January 2, 2015). The data was not available separately for HCA and non-HCA pipeline. Furthermore, because of the way pipeline HCA mileage and age mileage are reported, it is not possible to derive separate HCA and non-HCA pipeline age statistics.

[130] In some years, the miles of pipeline built before a certain time increases over time. For example, from 2006 to 2013, the miles of pipeline constructed between 1990 and 1999 increased from 17,735 miles to 19,323 miles. There are at least two possible explanations for this logically inconsistent data. One possible explanation is that pipeline may come back online after being inactive. Another possible explanation is the way the data is collected. This data is collected from annual reports completed by operators. As operators change hands or as additional miles of pipeline are assessed for the first time, they may find out that the line is older than they originally thought.

[131] http://www.dnvusa.com/Binaries/gasliquid_tcm153-378807.pdf (accessed June 7, 2014).

[132] This estimate was calculated using PHMSA 2013 annual report data downloaded from http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print (accessed January 2, 2015).

assessed HCA pipeline miles that is currently unpiggable may be pipeline segments that will be exempt from piggability requirements for technical reasons. For that reason, the estimate of 5.5 percent from the PHMSA 2013 annual report is considered a high estimate of the share of HL pipeline that is unpiggable.

Table 20 presents inspection data derived from the 2013 Annual Reports to PHMSA by HL pipeline operators. Pressure testing, external corrosion direct assessment (ECDA), and other methods cover much shorter segments of pipeline than the ILI tools. For example, the median length of pipe inspected by direct assessment is only 4 miles, while the median inspection length for ILI tools ranges from 69 to 135 miles. This data strongly suggests that inside of HCAs, non-ILI inspections are commonly used for short segments of specialized pipe incompatible with ILI inspections or for other specialized purposes such as testing newly constructed pipeline. Because the proposed requirement maintains exceptions for pipelines with design requirements incompatible with ILI, if implemented today the proposed requirement would affect less than 5.5 percent of HCA pipeline.

Table 20. HCA Assessment Methods by Mile in 2013[133]

	Miles of Pipeline Inspected				
Total HCA miles assessed or reassessed in 2013: 27,367 miles	**Total Inspection Miles**[134]	**Median**	**Mean**	**95th Percentile**	**Maximum**
ILI Tools					
• Corrosion or Metal Loss	36,420	76	195	984	2593
• Dent or Deformation	34,667	69	185	800	3205
• Crack or Long Seem Defect	12,802	100	242	930	2263
• Other ILI Tools	5,722	135	260	595	1908
Pressure Testing	5,356	10	37	201	395
ECDA	153	4	11	58	58
Other Methods	429	3	61	303	303

Given the aging of unpiggable line, advances in ILI technology, the small fraction of HCA pipeline that is currently unpiggable, the exceptions in the proposed requirement for specific types of pipeline with difficult to pig design requirements, and the 20-year compliance deadline, the proposed requirement is unlikely to impact a significant portion of the HL pipeline infrastructure.

For the purposes of this analysis, PHMSA assumed that only about 2 percent of current pipeline that could affect HCAs would be unpiggable pipeline absent the proposed requirement. The lower 2 percent figure partially reflects the fact that some of the current unpiggable pipeline will

[133] PHMSA pipeline inventory, https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?PortalPages (accessed January 2, 2015). Data was not available separately for HCA and non-HCA pipeline.

[134] Total inspection miles refers to the number of miles inspected by each method. Because HCA assessments often use more than one method of inspection on the same segment of pipeline, total inspection miles will be greater than the number of HCA miles assessed. Total assessment miles also includes portions of the assessment that covered non-HCA pipeline.

be allowed to remain unpiggable under the exceptions maintained in the proposed rule for technical infeasibility.

The quantitative costs and benefits will therefore be low. However, given that the pipelines that are subject to the requirement in 20 years will all be at least 45 years old (built before 1994) and that most of them will be at least 60 years old (built before 1975), the proposed piggability requirement will affect higher than average risk pipelines. Because of the proposed requirement, at that time operators of the older pipelines will have to decide whether to retrofit for piggability or replace the aging pipeline.

Alternatives Considered

Alternative 1: No Action (Baseline—Status Quo)

Not requiring operators to retrofit pipelines that cannot accommodate an ILI assessment after 20 years from the effective date of the final rule would not be in the interest of public safety and the protection of the environment in higher-risk areas that could affect HCAs. Modern ILI tools are capable of providing a relatively complete examination of the entire length of a pipeline, including information about threats that cannot always be identified using other assessment methods. ILI tools also provide superior information about incipient flaws, thereby allowing these conditions to be monitored over consecutive inspections and remediated before a pipeline failure occurs. Without this requirement, pipelines existing in newly identified HCAs would continue to be assessed by non-ILI methods. The risk from spills will not be curtailed or improved, and pipeline operators will not take advantage of the latest technology available to help protect the public and the environment.

For these reasons, PHMSA rejected the no-action alternative.

Alternative 2: Require ILI Assessment for All Pipelines

PHMSA believes that ILI tools provide the most useful information about conditions affecting pipe integrity and are superior to other assessment methods. Hydrostatic pressure testing, a well-recognized assessment method, reveals only those flaws that cause the pipe failures at pressures that exceed actual operating conditions. Pressure-test failures can also result in the release of test media and other products into the surrounding environment. ECDA can identify instances where coating damage may be affecting pipeline integrity. However, follow-up excavations and direct examinations are not always performed, and ECDA provides less information about pipe condition than ILI.

PHMSA believes that requiring ILI assessments will ensure that immediate action is taken to remediate anomalies that present an imminent threat to the integrity of HL pipelines in all locations. Moreover, many anomalies that would not qualify as immediate repairs under the current criteria will meet that requirement as a result of the additional conservatism that will be incorporated into the burst pressure calculations.

PHMSA opted to require operators to perform ILI assessments of all pipelines in areas that could affect HCAs. PHMSA is also proposing to require new timeframes for performing less imminent repairs, which will also allow operators to remediate those conditions in a timely manner while allocating resources to those areas that present a higher risk of harm to the public, property, and the environment.

This alternative was rejected based on the analysis of annual costs in excess of $200 million and annual benefits of approximately $20 million, which resulted in high negative net benefits.

Alternative 3: Propose to Require That All HL Pipelines in Areas That Could Affect an HCA Be Made Capable of Accommodating ILI Tools Within 20 Years Without Qualification

Short sections of pipe—such as manifolds, station piping, tank farm piping, and smaller lines—and other lines that ILI tools cannot go through due to their design or configuration —such as low-pressure lines, telescoping lines, sharp bends, and main-line valves that are not full opening—will have to be reconfigured to accommodate ILI tools. This alternative was rejected because preliminary estimates of costs suggested that the level of benefits would not justify those costs.

Analysis of Costs and Benefits of the Proposed Requirement

Analysis of Costs

PHMSA calculated costs under the assumption that only about 2 percent of current pipeline that could affect HCAs would remain unpiggable absent the proposed requirement. We also assume that operators will begin retrofitting for piggability in Year 19, 1 year before the compliance deadline of 20 years. The steps for calculating costs and savings are described below:

1. <u>Miles of Pipeline Affected</u>

   PHMSA assumes that in 20 years, 2 percent of HCA pipeline will not be piggable without the mandate. Then, 1,662 miles will need to be made piggable under this requirement.

   Miles of pipeline affected = 1,662

   (.02 * 83,104 miles of HCA pipeline)

2. <u>Costs of Retrofitting</u>

   A 2002 study of the cost of corrosion in the United States estimated that the cost for retrofitting "possible to convert" pipeline was between $30,000 and $90,000 per mile in 2013 dollars. The 2002 estimates included the cost of modifying pipeline to accommodate launchers and receivers, clearing bends, and replacing problem segments, including the cost of digging up pipeline and the loss of throughput.[135] [136] The Pipeline Integrity Management in High Consequence Area Final Regulatory Evaluation used an estimate of $32,000 for making lines piggable.[137] The Regulatory Evaluation for the Rural Onshore Low Stress Pipelines Rule, Phase II, contained a

[135] http://corrosioncost.com/pdf/gasliquid.pdf (accessed January 2, 2014). Appendix E from the NACE International 2002 report, Corrosion Costs and Preventive Strategies in the United States.
[136] See "The Ultimate Guide to Unpiggable Pipelines," http://pipelinesinternational.com/shop/the_ultimate_guide_to_unpiggable_pipelines/081249/ (accessed August 7, 2014).
[137] Pipeline Integrity Management in High Consequence Areas Final Regulatory Evaluation, Docket RSPA-A-00_7418, P19. Inflated to 2013 dollars with GDP deflator.

cost estimate of about $35,000 per mile. We use an estimate of $40,000 per mile in the range of the 2002 study and consistent with prior regulatory evaluations.[138] The costs are likely to be lower in 20 years, as smart pig technology continues to improve. For example, there are now free-swimming ILI tools, tethered ILI tools, and robotic ILI tools that may work in pipelines formerly considered unpiggable due to inaccessibility for a launcher and receiver.[139] Furthermore, since 1994, FR § 195.120 has required any line pipe, valve, fitting, or other line component installed as a replacement to be capable of accommodating ILI tools. Most of the difficulties from obstructions, including unsuitably designed valves and awkward bends, have been resolved through this process.[140]

Total Undiscounted Retrofitting Costs in Year 19 = $66.5 million

($40,000 per mile * 1662 miles)

Because any unpiggable pipeline must have been built before 1994, pipeline subject to this requirement will be at least 45 years old on the effective date. However, because pipeline constructed from the 1970s on is commonly piggable, most of the unpiggable pipeline subject to this rule will be at least 65 years old on the deadline for piggability. Therefore, we assume piggability will only extend the life of the pipeline for another 25 years.

Annualizing the retrofitting costs over 25 years at a 7-percent discount rate is 5.3 million. Discounting back 19 years at 7 percent yields a present value of the annualized costs of $1.6 million.

3. Cost of Post-ILI Repairs

Since the pipelines affected by this requirement are inside of HCAs, they are already assessed, even if not by ILI. Therefore, any additional findings of problems with the lines are likely to be something other than a leak, and repairs rather than replacement will be made. A study conducted for EPA suggests that a wrapping of gas pipelines can be accomplished for between approximately $5,600 and $22,015.[141] Although this report is on HL pipelines, we use the average of this cost range, or $13,800, in this analysis.

[138] See "The Ultimate Guide to Unpiggable Pipelines," http://pipelinesinternational.com/shop/the_ultimate_guide_to_unpiggable_pipelines/081249/ (accessed August 7, 2014).

[139] Editorial (2013). "Unpiggable…or not?" Journal of Pipeline Engineering, Vol 12, No 2.

[140] Ibid.

[141] There are several methods that can be used. See "Composite Wrap for Non-Leaking Pipeline Defects," http://epa.gov/gasstar/documents/ll_compwrap.pdf (accessed August 11, 2014.), or http://www.pipelinesinternational.com/news/advantages_of_steel_sleeves_over_composite_materials_for_pipeline_repair/061223/. Estimates are taken from p. 8 of the EPA reference. The lower bound estimate is based on the cost of composite wrap repair for a 6-inch defect in a gas pipeline with a 24-inch diameter. The upper bound estimate is based on pipeline replacement for a 234-inch defect in a pipe with the same specifications. For HL pipeline, replacement is more cost effective than repair for the 234-inch defect. The replacement cost estimate was adjusted to reflect the fact that unlike gas pipelines in which a significant amount of product must be vented during the replacement process, replacement of HL pipeline does not require a significant product loss.

According to the performance data presented in Table 3, from 2004 through 2013, operators assessed 214,642 miles of pipeline inside of HCAs and made 54,340 repairs. PHMSA assumes that the number of required repairs from moving from pressure testing or direct assessment to ILI will be 0.25 per mile, which corresponds to the difference in the average repair rate per mile for ILI of 0.27 minus the average repair rate per mile for pressure testing of 0.015 repairs per mile.

Undiscounted Post-ILI Repair Costs in Year 19 = $6.2 million

(0.27 repairs per mile * 1,662 miles * $13,800 average cost per repair)

Annualizing the costs over 5 years, the time between required assessments in HCA pipeline at a 7-percent discount rate is $1.4 million. Discounting back 19 years at a 7-percent discount rate yields a present value of $400,000.

4. Savings From Avoided Pressure Test Failures

The increased cost of post-ILI repairs will be partially offset by the reduction in the need to replace pipeline that ruptures or leaks during a pressure test and the associated cleanup of contaminated water that can result. Based on 2013 annual report data, the failure rate for pressure tests is 0.015 failures per mile.[142] We estimate the cost of repair/replacement and cleanup at $25,000 per failure.

Undiscounted Savings from avoided pressure test failures in Year 19 = 0.5$ million

(.015 repairs per mile * 1,662 miles * $25,000 average cost per repair)

Annualizing the savings over 5 years at a 7-percent discount rate is 0.1 million. Discounting back 19 years at a 7-percent discount rate yields a net present value of costs of $40,000.

5. Savings in Inspection Costs

The cost for performing hydrostatic testing is $15,000 per mile, versus the $5,150 average cost per mile of ILI. There could be considerable savings of $9,850 per mile if ILI could be a viable substitute for hydrostatic testing. For example, if all 1,662 miles of pipelines now inspected by hydrostatic means can eventually be inspected by ILI, the assessment costs savings every 5 years is estimated as follows:

Inspection Cost Savings When Substituting Pressure Tests for ILI in Year 19 = $16.4 million.

(1,662 miles * $9,850 per mile.)

Annualizing the savings over 5 years at a 7-percent discount rate is $3.7 million. Discounting back 19 years at a 7-percent discount rate yields $1 million.

[142] Calculated from publicly available detailed annual report data available at http://phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print.

Table 21. Summary of Cost Parameters

Parameters and Calculations	ILI	Pressure Test
Number of Miles Assessed per Year	1,662	1,662
Inspection Cost per Mile	$5,150	$15,000
Repairs per Mile	0.27	0.015
Cost per Repair	$13,800	$25,000
Retrofitting Cost per mile	$40,000	

Total annualized costs at a 7-percent discount rate is 1.0 million per year ($1.6 million retrofit + $400,000 ILI repairs - $40,000 pressure test repairs - $1.0 million in inspection cost savings due to switch from the more costly pressure testing to ILI inspections).

Analysis of Benefits

In addition to cost-savings benefits from switching from pressure testing to ILI, there are a number of well-documented risk reduction benefits of ILI relative to pressure testing.

- Comparisons of ILI results over time provide operators valuable information regarding the rate at which corrosion is progressing. Operators can use this information in their risk management decisions regarding pipeline repairs, replacement, and anti-corrosion measures.
- ILI is a non-destructive test that does not increase the risk of a pipeline failure. Pressure testing on the other hand does create the risk of a release of water contaminated with HLs if the pipeline ruptures during a test. Additionally, pressure testing puts stress on defects in the pipe, which may actually weaken the pipe during the corrosion process. Sometimes a pipeline will experience a reversal of pressure after a test, which means that the pipeline can fail at a pressure less than the test pressure. Pressure testing is usually carried out with water and a corrosive agent. The water used during a pressure test is itself a corrosive agent that must be thoroughly cleaned from the pipeline to avoid exacerbating corrosion problems.
- Pressure tests reduce risk for a shorter period of time than ILI tests. Pressure tests can only detect defects that fail at tested pressures. ILI on the other hand can detect smaller defects that do not fail at the tested pressure but may fail later as the corrosion process continues.[143] Because pressure tests are unable to capture non-critical defects, pressure tests need to be done more frequently than ILI, which detects defects earlier in the corrosion process to maintain the same level of risk.[144]

The benefits of the proposed requirement will depend on how much more effective than the other assessment methods ILI is in eliminating deaths, injuries, and property damages. The 1,662 miles of pipeline being considered under this proposed requirement are all inside of areas that could

---

[143] Keifner, John and Maxey, Willard. "The Benefits and Limitations of Hydrostatic Pressure Testing." Available at http://kiefner.com/downloads/apihydro.pdf (accessed December 20, 2014).

[144] Keifner, John and Maxey, Willard. "Periodic Hydrostatic Pressure Testing or IN-Line Inspection to Prevent Failures from Pressure-cycle-induced Fatigue." Available at http://kiefner.com/downloads/apifatigue.pdf (accessed December 20, 2014).

affect HCAs. As discussed previously, PHMSA estimates that each mile of HCA pipeline is associated with approximately $2,392 in annual societal cost. Over the course of 5 years, an ILI inspection over 1,662 miles of HCA pipeline will prevent 0.25 more losses per mile than a pressure test (0.27 repairs per mile for ILI minus the .015 repairs per mile for pressure testing). If we assume that each additional repair due to the ILI will prevent 0.10 incidents, then the marginal safety benefit of the ILI over the 5 years following the ILI assessment is as follows:

Marginal Safety Benefit of Requirement = 41.5 incidents avoided

(0.25 repairs per mile * 1,662 miles * 0.1 incidents per repair)

Between 2010 and 2013, there were 170 HCA incidents caused directly by corrosion according to PHMSA accident report data. Over the same time period, these incidents caused $198.6 million in social losses, or $1.2 million per HCA incident. Therefore, the cost benefit of an ILI inspection over the 5 years following the assessment is as follows:

Undiscounted Marginal Benefit of Requirement = $49.2 million

(1.2 million per incident * 4.51 incidents)

Assuming evenly spaced avoided incidents for simplicity, at a 7-percent discount rate the net present value of the benefits of the additional ILI is $41.2 million. Discounting back 20 years yields a net present value of annualized benefits of $10.1 million. The calculation of annualized net benefits is as follows:

Annualized Net Benefits at 7 percent = $11.2 million

(12.2 million in annualized benefits minus 1.0 million in annualized costs)

Interaction With Other Proposed Requirements

This requirement is not expected to interact significantly with any of the other requirements in terms of the net benefits. It only applies to the 14 percent of non-HCA pipeline that has not been assessed. This requirement and the other internal inspection requirements do not protect against the same types of hazards as the 72-hour post disaster inspection rule.

Requirement Area #8 – Clarify IM Requirements

Proposed action: There are three areas of clarification:

1. Correct inconsistency in IM plan deadlines for new pipelines.

   PHMSA is proposing to resolve an inconsistency between the deadline for drafting an IM plan for new pipelines[145] and other deadlines in the IM rule. Specifically, PHMSA proposes to require in §195.452(b)(1) that operators complete an IM plan for new pipeline segments that could affect an HCA before beginning operations. Under the current regulation, operators of these pipelines are required to complete an IM plan no later than 1 year after operations begin. However, operators of new pipelines are also currently required to identify HCA segments and to complete a baseline assessment on these segments before the pipeline is operational. Because plans to identify HCA segments and conduct a baseline integrity assessment are required to be in the IM plan, the current regulation is inconsistent. The proposed requirement corrects the inconsistency. It is not expected to have a significant impact on costs or benefits.

2. Increase specificity of the information analysis requirement in the IM plan.

   PHMSA is also proposing to add additional specificity to paragraph (g) by establishing a number of pipeline attributes that must be included in these analyses and to require explicitly that operators integrate analyzed information. Information integration is used in identifying interactions between threats or conditions affecting the pipeline and in setting priorities for dealing with identified issues. To ensure that spatial data is integrated into the information analysis, PHMSA is also proposing that operators consider explicitly any spatial relationships among anomalous information. It is not enough simply to use a computer-based geographic information system (GIS) to record this information. GIS systems can be beneficial in identifying spatial relationships, but analysis is required to identify where these relationships could result in situations adverse to pipeline integrity.

3. Require annual verification of HCA identification.

   PHMSA is proposing that operators verify their segment identification annually by determining whether factors considered in their analysis have changed. Section 195.452(b) currently requires that operators identify each segment of their pipeline that could affect an HCA in the event of a release, but there is no explicit requirement that operators assure that their identification of covered segments remains current. The change that PHMSA is proposing would not require that operators re-perform their segment analyses. Rather, it would require operators to identify the factors considered in their original analyses, determine whether those factors have changed, and consider whether any such change would be likely to affect the results of the original segment identification. If so, the operator would be required to perform a new analysis to validate or change the endpoints of the segments affected by the change.

[145] The new pipelines affected by this proposal are referred to as Category 3 pipelines in the tables with deadlines in the IM rule, §195.452. The definition of Category 3 pipelines in the IM rule includes pipelines constructed after May 29, 2001.

4. Clarify that IM requirement also applies to components of pipeline other than pipe.

   PHMSA is proposing to clarify through the use of an explicit reference that the IM requirements apply to portions of "pipelines" other than line pipe. Unlike integrity assessments for line pipe, section 195.452 does not include explicit deadlines for completing the analyses of other facilities within the definition of "pipeline" or for implementing actions in response to those analyses. Through IM inspections, PHMSA has learned that some operators have not completed analyses of their non-pipe facilities and have not implemented appropriate protective and mitigative measures.

5. Make explicit the requirement that IM plans include earthquake risk in the information analysis and implementation of preventive and corrective measures.

   Section 29 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 states that "[i]n identifying and evaluating all potential threats to each pipeline segment pursuant to parts 192 and 195 of title 49, Code of Federal Regulations, an operator of a pipeline facility shall consider the seismicity of the area." While seismicity is already mentioned at several points in the IM program guidance provided in Appendix C of Part 195, PHMSA is proposing to further comply with Congress's directive by including an explicit reference to seismicity in the list of risk factors that must be considered in establishing assessment schedules (§ 195.452(e)), performing information analyses (§ 195.452(g)), and implementing preventive and mitigative measures (§ 195.452(i)) under the IM requirements.

Alternatives Considered

Alternative 1: No Action (Baseline —Status Quo)

A decade's worth of IM inspection experience has shown that many operators are performing inadequate information analyses (e.g., they are collecting information but not affording it sufficient consideration). Integration is one of the most important aspects of the IM program, because it is used in identifying interactions between threats or conditions affecting the pipeline and in setting priorities for dealing with identified issues. For example, evidence of potential corrosion in an area with foreign line crossings and recent aerial patrol indications of excavation activity could indicate a priority need for further investigation. Consideration of each of these factors individually would not reveal any need for priority attention. PHMSA is concerned that under the status quo, a major benefit to pipeline safety intended in the initial rule is not being realized because of inadequate information analyses.

Under the status quo, there is no explicit requirement that operators ensure that their identification of segments that could affect an HCA remains current. As time goes by, the likelihood increases that factors considered in the original identification of covered segments may have changed. For example, new HCAs may be identified. Construction activities or erosion near the pipeline could change local topography in a way that could cause product released in an accident to travel further than initially analyzed. Changes in agricultural land use could also affect an operator's analysis of the distance released product could be expected to travel. Changes in the deployment of emergency response personnel could increase the time required to respond to a release and result in a larger area being affected by a potential release if the original segment identification relied on emergency response to limit the transport of released product.

PHMSA believes that operators should periodically revisit their initial analyses to determine whether they need to be updated. New HCAs may be identified.

Lastly, should PHMSA leave the IM plan requirements unchanged, there will remain the uncertainty that segments of pipelines that could affect HCAs have undergone change. Non-pipe facilities are already subject to IM plans, and not taking the proposed action of specifying compliance dates allows operators who have not fully complied with the original IM rule to continue to delay doing so. With respect to validation, no action could mean that areas that should be afforded additional protection (i.e., that meet criteria as an HCA) do not receive it. The risks associated with this alternative are the continuance of incidents that could have been avoided with more thorough IM plans.

Alternative 2: Integrate Data Elements

This alternative not only lists the data elements that have to be integrated, but also dictates how operators would have to integrate those listed data elements. PHMSA rejected this alternative because it was felt that it might unduly interfere with some management decisions (for example, how companies choose to manage their spatial data). This alternative would have specified that all information be included on a single drawing of specified size and scale (among other requirements), which would have required companies using a modern GIS to keep information on a hard-copy drawing solely to meet a regulatory requirement.

Alternative 3: Subject All Segments to IM Requirements

Applying IM requirements to all segments would require revising all current IM plans and increasing the cost of updating these plans annually. PHMSA recognizes that resources are limited and that subjecting all segments to IM requirements necessarily diverts resources from segments that pose the greatest hazard to low-hazard segments. PHMSA believes that limited safety resources should be applied preferentially to areas where an accident could cause the highest consequences—thus the focus on HCA. Applying the same requirements everywhere loses that and returns us to a situation in which areas with potentially higher consequences do not receive enhanced attention. Shifting resources to mitigate and prevent incidents in the newly covered segments could increase the risks in higher-hazard segments, thereby leading to worse safety outcomes.

Analysis of Costs and Benefits of the Proposed Action

Analysis of Costs

PHMSA believes that this is a clarification to existing requirements. Should some operators need to comply with the revised language, those operators will have to modify the types of analyses they are conducting and/or conduct additional analyses. Modification of existing analyses will involve some one-time transition costs (e.g., modifying a computer program that produces analytic reports) and could entail a marginal increase in the reoccurring costs of implementing those analyses (e.g., if there is an increase in the amount of labor required to analyze the data).

Costs associated with implementing new analyses could include the development of computer programs, acquisition of software, consulting assistance, and labor. None of the costs associated with analyses is likely to be significant because operators already conduct similar types of analyses under their IM programs; the cost increases will be marginal. This also applies to the new spatial analysis requirement. With the exception of distribution and gathering lines, pipeline operators are already required by the Pipeline Safety Improvement Act of 2002 to submit geospatial information to the National Pipeline Mapping System. In addition, over the last 10 years, a number of companies have started to offer a wide range of mapping software and/or services specifically designed to address IM requirements under the Pipeline Safety Improvement Act and resulting Department regulations. For example, some of these GIS products/services cover HCA analyses, risk assessments, spill impact analyses, and data integration analyses. The number of available vendors and products that are offered in this area, as well as the examples of projects that have already been implemented, indicates that operators have already been using geospatial analysis to integrate anomalous data. PHMSA invites comments on the estimated costs of adding specificity to information analyses. Cost estimates have been constructed to be consistent with the PHMSA information collections covering IM in HCAs, “Integrity Management in High Consequence Areas for Operators of Hazardous Liquid Pipeline” (OMB Control No. 2137-0605). IM plans require labor from administrative personnel, engineers, senior engineers, and pipeline operator management. For administrative time, this analysis uses the median wage for Office and Administrative Support Occupations ($18.10 per hour); for engineers, the median wage for Architecture and Engineering Occupations ($43.75 per hour); for senior engineers ($69.93 per hour); and for pipeline management, the median wage for Management Occupations ($68.71 per hour). Total labor costs of performing this work include the cost of benefits—an additional 50 percent of wages.[146] Table 22 shows these wage calculations and the total labor cost for IM Assessments.[147]

PHMSA assumed in the supporting statement for its IM information collections that completing an initial IM plan takes a total of 1,400 labor hours—comprising 400 hours of administrative time, 800 hours of engineers’ time, and 200 hours of senior engineers’ time. It also estimated that updating an IM plan annually takes a total of 810 hours—comprising 70 hours of administrative time, 200 hours of engineers’ time, 40 hours of senior engineers’ time, and 500 hours of supervisory time. On May 4, 2012, OMB approved the time estimates for creating and updating an IM plan.[148]

[146] BLS, Occupational Employment Statistics, May 2010.

[147] See 2137-0605: Pipeline Integrity Management in High Consequence Areas for Operators of Hazardous Liquid Pipelines, http://www.reginfo.gov/public/do/DownloadDocument?documentID=299498&version=1 (accessed on August 17, 2012). PHMSA had previously separated these activities into two information collections according to length of pipe (OMB Control No. 2137-0605 for less than 500 miles and OMB Control No. 2137-0605 for greater than 500 miles of pipe). The OMB-approved renewal on May 4, 2012, combined these into a single information collection with identical time estimates for all lengths of pipe. For more information, see also 2137-0604: Pipeline Integrity Management in High Consequence Areas Operators with more than 500 Miles of Hazardous Liquid Pipelines.

[148] See “Notice of Office of Management and Budget Action: Pipeline Integrity Management in High Consequence Areas Operators with more than 500 Miles of Hazardous Liquid Pipelines,” May 4, 2012, http://www.reginfo.gov/public/do/PRAOMBHistory?ombControlNumber=2137-0605#.

Table 22. Labor Costs of IM Plans

	Base Wage	Wage + Benefits	Initial Plan Labor Hours	Initial Plan Labor Cost	Updated Plan Labor Hours	Updated Plan Labor Cost
Admin	$18.10	$27.15	400	$10,860	70	$1,900
Engineer	$43.75	$65.63	800	$52,504	200	$13,126
Senior Engineer	$69.93	$104.90	200	$20,980	40	$4,196
Supervisor	$68.71	$103.06	0	$0	500	$51,530
Rounded Total	-	-	1,400	$84,344	810	$70,752

All operators currently update their IM plans annually. PHMSA proposes that operators identify factors that could lead to revisions and to integrate non-pipe facilities into these plans. HL pipeline operators who were conscientious in their original implementation of IM and included non-pipe facilities in their analyses and actions will not be required to do anything more in response to the proposed new requirements. Both of these activities would add more complexity to the annual updates but would not make this activity more costly than creating the initial plans. Although data do not exist to precisely estimate the costs of these proposals, PHMSA can assume that their marginal cost does not exceed the difference in cost of creating an initial plan ($84,344) and performing an annual update ($70,752). That is, the maximum cost associated with revising IM plans would not exceed $13,592 per operator per year; PHMSA, however, estimates that it would be smaller than that. HL operators have reported on the methods they use to assess the integrity of their pipelines, the number of pipeline miles assessed using each method, the operator's excavation and repair activities addressing time-sensitive conditions, and anomalies discovered through these integrity assessments. Some operators may have included facilities in their IM plans as the original IM rule intended, and some, to mitigate their own losses, may have already verify covered segments, as this proposal would require.

Assuming that all HL pipeline operators have reported on their IM programs, the maximum cost of this provision is approximately $5.7 million ($13,592 * 421 operators). The present value of the cost is approximately $87 million at 3 percent and $64 million at 7 percent over 20 years. PHMSA seeks comment on the estimated costs of the proposed requirements associated with the preparation and annual updating of IM plans.

Annualized costs discounted at 3 percent and 7 percent are approximately $4.4 million and $3.2 million, respectively.

Analysis of Benefits

Clarifying the requirements will strengthen the types of risk assessment analyses being conducted by operators as part of their IM programs. Such improvements will help mitigate potential pipeline failures that may otherwise go undetected. The benefits of reduced costs associated with the prevention or reduction of released HLs cannot be quantified but could vary in frequency and size, depending on the types of failures that are averted.

IM plans are intended to identify segments of pipelines that, if they were to release an HL, would result in the most significant damages to society. In the past, covered segments have been confined to HCAs, but the risks in non-HCAs have also been significant. Although HCAs are already covered by IM plan requirements, PHMSA proposes to require operators to assess annually whether portions of non-covered segments fall inside of new HCAs. It cannot be determined what, if any, of HL incident costs are associated with incidents that occurred in segments that operators did not know were located inside of HCAs, but industry comments to the ANPRM seem to indicate that operators are aware of new HCA designations. However, pipe segments can affect HCAs even if not located in these areas, and this proposal would require that operators identify risks inside of non-HCA areas of pipe and, if necessary, cover those segments in their IM plans. Consequently, benefits associated with this provision of the proposed rule would most likely be confined to eliminating or mitigating some incidents that occurred outside of HCAs.

The societal costs associated with pipelines outside of HCAs are approximately $178.3 million per year. If we assume a modest 10-percent effectiveness in reducing incidents ensuing from this requirement, benefits are estimated to be approximately $17.8 million per year. The present value of benefits is approximately $273.2 million at 3 percent over a 20-year period and $202.1 million at 7 percent over a 20-year period.

Annualized benefits are approximately $13.7 million discounted at 3 percent and $10 million discounted at 7 percent.

With respect to non-pipe IM plans, operators are currently required to include non-pipe facilities in IM plans. PHMSA, however, had not specified compliance dates for including non-pipe facilities in assessments and stated that it believed some operators had not yet included facilities in their IM plans. Although the proposal merely specifies compliance dates for a current provision, because there is less than full compliance with the current IM rules regarding facilities, the benefits and costs of subsequent PHMSA actions should be evaluated against the actual baseline level of compliance. PHMSA cannot determine what, if any, costs are associated with incidents that occurred in facilities that had not been covered in IM plans and therefore cannot estimate benefits of this clarification.

Comparison of Costs and Benefits

Conceptually, some of the benefit derives from better tracking of HCAs and non-HCAs over time. If HCAs are correctly identified, a greater number of inspections will occur in areas that could affect HCAs and hence, in principle, engender lower accident rates. The accidents averted are higher-severity accidents, since they would have occurred in HCAs. Thus, these proposals would mitigate or prevent some fraction of total HL incident costs. Many operators may already comply with the proposed requirements or be able to do so at a much lower cost. Consequently, the new cost borne by operators is likely to be only a fraction of this estimate.

Based on the information presented here, the present value of costs and benefits over a 20-year period are approximately $64 million and $202 million, respectively, at 7 percent. Thus, net benefits are approximately $138 million ($202 million–$64 million) over 20 years. Annualized net benefits discounted at 7 percent are $6.8 million ($10 million–$3.2 million). PHMSA seeks comments on these estimates.

Appendix A. Potentially Assessment-Preventable Incidents, 2010 to 2014

	Incident Date	City	State	Cause	Commodity Type	Total Release (Gallons)	Total Reported Costs (2014 $)
1	7/17/2012	JACKSON	WI	Material/Weld Failure	Non-HVL	54,684	24,066,694
2	5/18/2013	CUSHING	OK	Internal Corrosion	Crude Oil	94,332	14,093,257
3	4/28/2012	TORBERT	LA	Material/Weld Failure	Crude Oil	120,960	7,949,164
4	11/29/2011	FULSHEAR	TX	External Corrosion	Crude Oil	4,200	6,230,237
5	7/27/2012	GRAND MARSH	WI	Material/Weld Failure	Crude Oil	72,618	5,196,469
6	1/8/2010	NECHE	ND	Material/Weld Failure	Crude Oil	158,928	4,480,263
7	2/23/2013	CHESTER	TX	Internal Corrosion	Crude Oil	23,100	3,699,972
8	4/25/2014	HAYNESVILLE	LA	Internal Corrosion	Crude Oil	16,800	3,341,545
9	1/12/2010	PAWNEE	OK	Material/Weld Failure	HVL	18,900	2,688,997
10	5/29/2010	CONSTANTINE	MI	Material/Weld Failure	Non-HVL	89,082	2,099,027
11	8/27/2010	GILBOA	NY	Material/Weld Failure	HVL	137,886	1,935,088
12	4/8/2012	CUSHING	OK	Internal Corrosion	Crude Oil	25,200	1,759,989
13	9/3/2013	THREE RIVERS	TX	External Corrosion	Non-HVL	115,584	1,754,695
14	9/8/2011	LATAN	TX	Material/Weld Failure	HVL	556,122	1,581,417
15	12/17/2012	CHAUTAUQUA	KS	External Corrosion	Crude Oil	4,200	1,568,892
16	5/7/2014	PASADENA	TX	External Corrosion	Non-HVL	31,250	1,470,000
17	5/12/2014			External Corrosion	Crude Oil	4	1,450,000
18	3/21/2014	MAXBASS	ND	Internal Corrosion	Crude Oil	8,400	1,379,751
19	7/18/2013	SULPHUR	LA	Material/Weld Failure	HVL	748,650	1,341,630
20	10/2/2014	BANQUETE	TX	Internal Corrosion	Crude Oil	273	1,171,548
21	6/8/2012	MORAN	KS	Material/Weld Failure	Non-HVL	12,768	987,102
22	8/12/2011	HENRIETTA	TX	External Corrosion	Non-HVL	38,997	981,656
23	11/21/2012	FAIRMONT	NE	Material/Weld Failure	Non-HVL	2,520	966,875
24	1/19/2011	MAYSVILLE	OK	Internal Corrosion	Crude Oil	52,500	860,475
25	7/22/2013	RUGBY	ND	Material/Weld Failure	Crude Oil	11	750,656
26	1/24/2013	RANGER	TX	Internal Corrosion	Crude Oil	14,700	747,881
27	6/16/2011	TAFT	TX	External Corrosion	HVL	21,000	679,547
28	4/6/2011	JENNINGS	LA	Material/Weld Failure	HVL	21,220	589,468

	Incident Date	City	State	Cause	Commodity Type	Total Release (Gallons)	Total Reported Costs (2014 $)
29	11/8/2011	JENNINGS	LA	Material/Weld Failure	HVL	21,010	581,895
30	12/18/2014	SHEVLIN	MN	Internal Corrosion	Crude Oil	840	564,940
31	6/3/2013	VICTORIA	TX	Material/Weld Failure	Non-HVL	8,400	564,472
32	9/25/2014	LAKESIDE CITY	TX	External Corrosion	Crude Oil	5,376	560,500
33	9/30/2014	CHICO	TX	External Corrosion	Crude Oil	420	560,500
34	7/15/2013	YORK	ND	Material/Weld Failure	Crude Oil	84	527,970
35	8/12/2013	ERIE	IL	Material/Weld Failure	HVL	772,800	524,262
36	7/25/2014	HAHNVILLE	LA	External Corrosion	HVL	1	515,269
37	8/7/2011	HENRIETTA	TX	External Corrosion	Non-HVL	5,502	502,075
38	11/20/2010	NEW WAVERLY	TX	Material/Weld Failure	Crude Oil	4,200	467,880
39	11/1/2014	KINGFISHER	OK	Material/Weld Failure	Crude Oil	630	424,000
40	2/8/2010	LAKE ARTHUR	LA	Material/Weld Failure	Crude Oil	210	406,295
41	1/11/2010	TAFT	TX	Material/Weld Failure	Non-HVL	126	381,589
42	1/22/2014	GARY	TX	External Corrosion	Non-HVL	16,800	378,368
43	5/2/2013	KNOX	ND	Material/Weld Failure	Crude Oil	63	366,175
44	7/22/2013	JACKSBORO	TX	Internal Corrosion	Crude Oil	2,100	344,079
45	6/3/2010	GOLDSMITH	TX	External Corrosion	HVL	193,956	324,974
46	2/15/2012	STERLING	MI	Material/Weld Failure	Crude Oil	840	310,892
47	12/14/2011	PONCA CITY	OK	Material/Weld Failure	Non-HVL	10,500	302,899
48	5/8/2013	LABADIEVILLE	LA	Material/Weld Failure	HVL	42	291,144
49	2/20/2012	ABERDEEN	SD	Material/Weld Failure	Non-HVL	21,000	276,010
50	2/8/2013	CHESTER	TX	Internal Corrosion	Crude Oil	294	274,903
51	9/13/2012	FORSAN	TX	Material/Weld Failure	HVL	281,400	273,585
52	10/5/2013	TYLER	TX	External Corrosion	Crude Oil	1,260	271,046
53	5/10/2012	CHILDRESS	TX	External Corrosion	Crude Oil	840	268,956
54	11/1/2010	WHITEWRIGHT	TX	External Corrosion	HVL	10,122	267,401
55	12/6/2010	VAN	TX	External Corrosion	Crude Oil	126	267,018
56	4/15/2014		TX	External Corrosion	Crude Oil	7,266	247,985
57	4/12/2013	COTULLA	TX	Internal Corrosion	Crude Oil	676	247,639
58	7/22/2013	CLUTE	TX	Internal Corrosion	Non-HVL	8	240,244

	Incident Date	City	State	Cause	Commodity Type	Total Release (Gallons)	Total Reported Costs (2014 $)
59	11/3/2012			External Corrosion	Crude Oil	5	238,356
60	5/7/2013	GRAND FORKS	ND	Material/Weld Failure	Crude Oil	42	235,574
61	3/30/2011	HABBERMAN	ID	External Corrosion	Non-HVL	9,576	230,220
62	12/27/2011	KERMIT	TX	Material/Weld Failure	HVL	137,886	228,623
63	1/2/2014	CARNERAS	CA	External Corrosion	Crude Oil	18,480	223,357
64	12/20/2010	KINDER	LA	Material/Weld Failure	Carbon Dioxide	2,948,034	219,644
65	7/1/2013	BRADGATE	IA	Material/Weld Failure	HVL	1,063	213,437
66	3/21/2014	SNYDER	TX	Material/Weld Failure	HVL	167,664	204,164
67	4/3/2010	GOWER	MO	Internal Corrosion	Crude Oil	840	202,122
68	10/10/2012	CUSHING	OK	Internal Corrosion	Crude Oil	3,150	200,553
69	7/12/2011	PATOKA	IL	Internal Corrosion	Crude Oil	38	199,186
70	9/9/2013	BAY CITY	TX	Internal Corrosion	Crude Oil	6,300	189,091
71	3/27/2012	GARRISON	TX	Material/Weld Failure	HVL	4,200	184,755
72	2/13/2013	MT. VERNON	MO	External Corrosion	Non-HVL	2,239	176,996
73	12/17/2012	GREENWOOD	NE	Material/Weld Failure	HVL	1,000	176,374
74	7/23/2010	PICKRELL	NE	Material/Weld Failure	HVL	20	174,268
75	9/15/2011	BLEIBLERVILLE	TX	Material/Weld Failure	HVL	15	170,955
76	2/14/2011	BEAUMONT	TX	Material/Weld Failure	Carbon Dioxide	1,813,661	169,247
77	2/21/2011	CUSHING	OK	Material/Weld Failure	Crude Oil	25,200	168,964
78	2/6/2013	RANGER	TX	Internal Corrosion	Crude Oil	1,050	166,922
79	12/4/2010	LIVINGSTON	TX	Internal Corrosion	Crude Oil	3,150	165,915
80	3/10/2014	CUSHING	OK	Internal Corrosion	Crude Oil	15,162	165,750
81	12/30/2011	PLAINVILLE	KS	Material/Weld Failure	Crude Oil	6,300	165,725
82	2/17/2011	MEDFORD	OK	External Corrosion	HVL	2,100	165,309
83	1/26/2013	LEEDS	ND	Material/Weld Failure	Crude Oil	10	161,792
84	2/26/2013	CUSHING	OK	External Corrosion	Crude Oil	420	161,758
85	6/1/2010	MCKITTRICK	CA	External Corrosion	Crude Oil	21,336	160,211
86	6/29/2011	NEBRASKA CITY	NE	Material/Weld Failure	Non-HVL	126	160,147
87	4/6/2013	LOCKHART	MS	Previous Damage	Non-HVL	42	152,842
88	7/23/2011	EL DORADO	KS	External Corrosion	Crude Oil	1,470	149,790

	Incident Date	City	State	Cause	Commodity Type	Total Release (Gallons)	Total Reported Costs (2014 $)
89	9/10/2014	ORLA	TX	External Corrosion	Crude Oil	718	148,568
90	6/28/2010	STRAWN	IL	Internal Corrosion	Non-HVL	126	144,190
91	12/11/2013	CELESTE	TX	External Corrosion	Crude Oil	840	134,374
92	5/14/2012	CUSHING	OK	Material/Weld Failure	Crude Oil	30	129,538
93	2/14/2013	BENTON	KS	Internal Corrosion	HVL	840	127,961
94	2/9/2013	BRECKENRIDGE	TX	Internal Corrosion	Crude Oil	630	120,018
95	11/16/2011	CUSHING	OK	Internal Corrosion	Crude Oil	5,880	117,631
96	2/3/2013	BRECKENRIDGE	TX	Internal Corrosion	Crude Oil	1,050	117,539
97	6/9/2011	MILFORD	IA	Previous Damage	Non-HVL	168	113,351
98	10/25/2012	JACKSBORO	TX	Internal Corrosion	Crude Oil	18,900	99,278
99	2/2/2014	ROLLING HILLS	WY	Material/Weld Failure	HVL	70,980	98,668
100	11/9/2010	HAVEN	KS	Internal Corrosion	Crude Oil	3,990	98,209
101	12/8/2014	STANTON	TX	Internal Corrosion	Crude Oil	840	97,900
102	6/18/2011	CUSHING	OK	Internal Corrosion	Crude Oil	798	81,403
103	2/14/2012		OK	Internal Corrosion	Crude Oil	4,200	77,723
104	1/9/2010	GALENA PARK	TX	Material/Weld Failure	Non-HVL	1,470	75,192
105	5/20/2010	GORDON	TX	External Corrosion	HVL	5,002	74,765
106	6/30/2010	LANGDON	KS	Material/Weld Failure	HVL	84	72,791
107	11/15/2010	EARLY	IA	Material/Weld Failure	HVL	362	72,021
108	10/15/2013		MS	Material/Weld Failure	Carbon Dioxide	4	71,768
109	5/19/2012	AMBOY	MN	Material/Weld Failure	HVL	143	71,413
110	2/14/2011	WYNNEWOOD	OK	Internal Corrosion	Crude Oil	3,276	70,611
111	11/6/2010	CHICO	TX	External Corrosion	Crude Oil	840	69,532
112	6/10/2013		NM	Material/Weld Failure	Carbon Dioxide	873,726	68,892
113	7/13/2014	HOBBS	NM	Internal Corrosion	Crude Oil	5,040	68,000
114	2/18/2013	PORT ARTHUR	TX	External Corrosion	Non-HVL	42	67,284
115	12/10/2014	LOST HILLS	CA	Internal Corrosion	Crude Oil	33	63,050
116	9/23/2013	FROST	MN	Material/Weld Failure	HVL	690	59,373
117	3/18/2010	CUSHING	OK	External Corrosion	Crude Oil	294	57,676
118	2/27/2014	CUSHING	OK	Internal Corrosion	Crude Oil	63	56,650

	Incident Date	City	State	Cause	Commodity Type	Total Release (Gallons)	Total Reported Costs (2014 $)
119	4/11/2012	STRAWN	IL	Internal Corrosion	Non-HVL	1,749	54,924
120	12/6/2011	NEDERLAND	TX	Material/Weld Failure	Crude Oil	1,302	54,913
121	5/10/2010	HOBBS	NM	External Corrosion	Crude Oil	84	54,579
122	7/24/2011	MCCAMEY	TX	Internal Corrosion	Crude Oil	5,166	52,590
123	4/27/2011	RINGGOLD	TX	Internal Corrosion	Crude Oil	336	52,501
124	11/13/2011	HERMELEIGH	TX	Material/Weld Failure	Crude Oil	3,780	51,953
125	9/23/2013	BRADGATE	IA	Material/Weld Failure	HVL	190	51,170
126	5/18/2013	DECATUR	NE	Material/Weld Failure	HVL	101	51,021
127	11/3/2014	GRAHAM	TX	Internal Corrosion	Crude Oil	42	50,080
128	2/24/2014	CLARKSON	KY	Internal Corrosion	Crude Oil	42	48,200
129	7/29/2010	HAVEN	KS	Internal Corrosion	Crude Oil	840	48,063
130	1/6/2011		TX	External Corrosion	HVL	71	47,568
131	6/20/2011	WINK	TX	Internal Corrosion	Crude Oil	11,550	46,778
132	9/18/2012	MCCAMEY	TX	Internal Corrosion	Crude Oil	420	45,598
133	6/15/2012	EL DORADO	KS	Internal Corrosion	Crude Oil	2,520	45,307
134	9/9/2012	POCAHONTAS	IA	Material/Weld Failure	HVL	2,295	44,037
135	3/15/2011		OK	Material/Weld Failure	HVL	42	43,342
136	9/27/2013	KALKASKA	MI	Internal Corrosion	Crude Oil	237	43,218
137	12/1/2011	NO TREES	TX	External Corrosion	Non-HVL	210	42,669
138	11/2/2013	CUSHING	OK	External Corrosion	Crude Oil	95	42,460
139	11/20/2012	LYSITE	WY	Internal Corrosion	Crude Oil	315	42,074
140	2/21/2014	LONGVIEW	TX	Internal Corrosion	Crude Oil	630	41,885
141	3/20/2012	CASS LAKE	MN	Material/Weld Failure	Crude Oil	1	41,452
142	9/20/2011	WORLAND	WY	Internal Corrosion	Crude Oil	4,032	41,247
143	9/5/2012	DENHART	IA	Material/Weld Failure	HVL	369	39,109
144	4/7/2010	WALNUT SPRINGS	TX	Material/Weld Failure	Non-HVL	30	39,081
145	9/4/2011	BORGER	TX	Internal Corrosion	Crude Oil	197	38,378
146	1/2/2013	PADACUH	TX	External Corrosion	Crude Oil	84	37,979
147	2/7/2013	CHESTER	TX	Internal Corrosion	Crude Oil	126	37,756
148	5/23/2013	BARNESVILLE	MN	Material/Weld Failure	Non-HVL	5	37,497

	Incident Date	City	State	Cause	Commodity Type	Total Release (Gallons)	Total Reported Costs (2014 $)
149	11/23/2013	BEAVER	OK	Material/Weld Failure	Carbon Dioxide	27,040	37,437
150	7/27/2011		OK	Material/Weld Failure	HVL	10	36,875
151	4/19/2013	CUSHING	OK	External Corrosion	Crude Oil	210	36,077
152	7/1/2014	ENID	OK	Material/Weld Failure	HVL	176	36,000
153	4/28/2010	SCHALLER	IA	Material/Weld Failure	HVL	17	34,210
154	2/21/2014	HERMLEIGH	TX	Internal Corrosion	Crude Oil	504	33,976
155	11/27/2010	MILLERSBURG	IA	Material/Weld Failure	HVL	97	33,121
156	1/13/2010	GALENA PARK	TX	Material/Weld Failure	Non-HVL	252	32,581
157	2/21/2014	DAISETTA	TX	Material/Weld Failure	HVL	23	32,500
158	1/14/2011	CUSHING	OK	Internal Corrosion	Crude Oil	84	31,818
159	7/4/2010	DRUMRIGHT	OK	Internal Corrosion	Crude Oil	42	31,413
160	10/23/2010	SANTO	TX	Material/Weld Failure	HVL	260	31,134
161	12/21/2010	GENEVA	NE	External Corrosion	Non-HVL	75	30,720
162	10/3/2011	TORRANCE	CA	External Corrosion	Crude Oil	1,722	30,659
163	8/19/2010	ST. JAMES	LA	Internal Corrosion	Crude Oil	25	30,440
164	4/24/2014	BEGGS	OK	Internal Corrosion	Crude Oil	126	30,296
165	9/23/2011	OLNEY	TX	External Corrosion	Crude Oil	21	29,663
166	7/13/2011	WORTHAM	TX	Internal Corrosion	Crude Oil	2,940	29,015
167	2/26/2014		OK	External Corrosion	Crude Oil	42	29,000
168	2/22/2010	BIG SPRING	TX	External Corrosion	HVL	4,914	28,688
169	9/21/2012	HERMLEIGH	TX	External Corrosion	Crude Oil	20	27,507
170	9/1/2011	LONG BEACH	CA	External Corrosion	Crude Oil	20	27,393
171	10/19/2011	CLAUDE	TX	Material/Weld Failure	HVL	15	26,413
172	1/23/2013	ADDINGTON	OK	Material/Weld Failure	Crude Oil	126	25,704
173	7/23/2014			External Corrosion	Crude Oil	63	25,149
174	1/11/2012	HULL	TX	Internal Corrosion	Crude Oil	84	23,969
175	6/25/2010	HERMLEIGH	TX	Internal Corrosion	Crude Oil	84	23,938
176	12/5/2010	HERMLEIGH	TX	Internal Corrosion	Crude Oil	252	22,964
177	1/17/2013	EL DORADO	AR	Material/Weld Failure	Crude Oil	1,310	22,599
178	8/20/2012	WHITE OAK	TX	Internal Corrosion	Crude Oil	210	22,488

	Incident Date	City	State	Cause	Commodity Type	Total Release (Gallons)	Total Reported Costs (2014 $)
179	4/14/2011		OK	Material/Weld Failure	HVL	60	22,241
180	9/27/2013	KALKASKA	MI	Internal Corrosion	Crude Oil	103	22,161
181	2/5/2013	GOLDSMITH	TX	External Corrosion	Crude Oil	357	21,225
182	10/23/2013	ABILENE	TX	External Corrosion	HVL	336	20,702
183	9/16/2010	ANSON	TX	Material/Weld Failure	Crude Oil	21	20,149
184	11/14/2013	EDMOND	OK	Internal Corrosion	Crude Oil	294	19,985
185	7/7/2012	KURTEN	TX	External Corrosion	Crude Oil	84	18,821
186	2/21/2010	MCCAMEY	TX	Internal Corrosion	Crude Oil	378	18,675
187	7/12/2012	KURTEN	TX	External Corrosion	Crude Oil	5	18,654
188	10/3/2011	MIDKIFF	TX	External Corrosion	HVL	420	18,437
189	3/20/2010	METTLER	CA	Internal Corrosion	Crude Oil	10,080	17,944
190	11/2/2012	CROWVILLE	LA	Internal Corrosion	Crude Oil	63	17,824
191	11/23/2012	GUERNSEY	WY	Internal Corrosion	Crude Oil	840	16,063
192	7/1/2014	STINNETT	TX	External Corrosion	Carbon Dioxide	155,148	16,000
193	3/2/2012	HULL	TX	Internal Corrosion	Crude Oil	5	15,557
194	9/25/2014	SNYDER	TX	Previous Damage	Crude Oil	42	15,090
195	10/6/2014	GOLDSMITH	TX	Internal Corrosion	Crude Oil	18	15,050
196	2/24/2014	RURAL	OK	External Corrosion	Crude Oil	210	15,000
197	5/13/2014		MS	Internal Corrosion	Crude Oil	168	14,204
198	5/23/2012	EDMOND	OK	Internal Corrosion	Crude Oil	210	13,140
199	8/1/2011	BAKERSFIELD	CA	External Corrosion	Crude Oil	84	12,906
200	8/15/2012	SOUR LAKE	TX	External Corrosion	Crude Oil	126	12,905
201	4/19/2013		OK	Internal Corrosion	Crude Oil	126	12,623
202	11/12/2012	SARATOGA	TX	Internal Corrosion	Crude Oil	21	12,478
203	7/27/2014	HOBBS	NM	Internal Corrosion	Crude Oil	336	12,000
204	8/5/2010	CRANE	TX	Internal Corrosion	Crude Oil	189	11,796
205	8/20/2010	SHERWOOD	ND	Internal Corrosion	Crude Oil	16	11,776
206	5/20/2010	HUDSON	KS	Internal Corrosion	Crude Oil	5	11,762
207	8/31/2011	PRICE	TX	Internal Corrosion	Crude Oil	84	11,488
208	4/4/2011	MCCAMEY	TX	Internal Corrosion	Crude Oil	168	11,484

	Incident Date	City	State	Cause	Commodity Type	Total Release (Gallons)	Total Reported Costs (2014 $)
209	6/10/2011	RINGLING	OK	Internal Corrosion	Crude Oil	10	11,108
210	9/18/2012	OLNEY	TX	External Corrosion	Crude Oil	42	10,985
211	6/7/2010	GRENORA	ND	Material/Weld Failure	Crude Oil	42	10,755
212	7/12/2010	LONGVIEW	TX	Internal Corrosion	Crude Oil	20	10,718
213	5/23/2010	COLORADO CITY	TX	Internal Corrosion	Crude Oil	168	10,643
214	4/3/2013	MCCAMEY	TX	Internal Corrosion	Crude Oil	42	10,587
215	4/4/2012	MIDLAND	TX	Internal Corrosion	Crude Oil	126	10,570
216	10/22/2013	BILLINGS	OK	External Corrosion	Crude Oil	294	10,180
217	4/28/2011	MIDLAND	TX	External Corrosion	Crude Oil	84	9,956
218	10/21/2014	MIDLAND	TX	Internal Corrosion	Crude Oil	168	7,900
219	8/15/2012	HOBBS	NM	Internal Corrosion	Crude Oil	168	7,669
220	4/20/2011	FREEPORT	TX	Internal Corrosion	Crude Oil	42	7,480
221	10/7/2011	HOOKER	OK	Internal Corrosion	Crude Oil	714	6,406
222	4/19/2012	MARCIOPA	CA	Internal Corrosion	Crude Oil	113	6,249
223	9/1/2014	JAL	NM	Internal Corrosion	Crude Oil	42	5,600
224	8/12/2011	HUDSON	KS	Internal Corrosion	Crude Oil	126	5,373
225	7/9/2011	CUSHING	OK	Internal Corrosion	Crude Oil	25	5,320
226	7/19/2013	WICHITA FALLS	TX	Internal Corrosion	Crude Oil	168	4,581
227	5/28/2014	FREEMAN	MO	External Corrosion	Crude Oil	30	4,580
228	2/27/2012	MAYSVILLE	OK	Internal Corrosion	Crude Oil	84	4,407
229	9/3/2010	HUGOTON	KS	Internal Corrosion	Crude Oil	84	4,400
230	1/15/2010	ELLIS	KS	Internal Corrosion	Crude Oil	210	4,144
231	6/11/2012	JONES CREEK_ TX	TX	Material/Weld Failure	Crude Oil	11	3,653
232	9/4/2014	MINCO	OK	Material/Weld Failure	HVL	143	3,650
233	6/13/2012	WILSON	OK	External Corrosion	Crude Oil	20	3,368
234	6/20/2012	LONGVIEW	TX	Internal Corrosion	Crude Oil	5	3,015
235	12/19/2012	RINGGOLD	TX	Internal Corrosion	Crude Oil	42	2,985
236	6/18/2011	HERMLIEGH	TX	Internal Corrosion	Crude Oil	42	1,675
237	12/6/2010	SEMINOLE	TX	Material/Weld Failure	HVL	109	1,121
238	9/4/2013	ALEX	OK	Internal Corrosion	Crude Oil	42	204