Application of Safety Regulation to Rural Onshore Hazardous Liquid Low Stress Pipelines (Phase II)

Volume II
Regulatory Analysis

Prepared For:

PHMSA

Pipeline and Hazardous Materials Safety Administration

Prepared By:

Economics
Public Policy
Planning

Jack Faucett Associates

Since 1963

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1. INTRODUCTION

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is proposing to extend pipeline safety regulations in 49 CFR Part 195 to rural low stress hazardous liquid pipelines (referred to as low stress pipelines) that have not previously been subject to regulation.

This regulatory report consists of two volumes. Volume I of the regulatory analysis identifies potential regulatory alternatives and presents the conclusions of the regulatory analysis. Volume I contains the following chapters:

- **Chapter 1: Introduction** – summarizes the need and intent of the regulation, and reviews previous regulatory and legislative actions.
- **Chapter 2: Regulatory Alternatives** – describes the alternatives considered in the previous Low Stress Phase I, reviews criteria for the development of regulatory alternatives suggested by the Office of Management and Budget (OMB) and presents the six alternatives considered for this rulemaking.
- **Chapter 3: Low Stress Characteristics** – presents estimates of affected Phase II low stress pipeline mileage, compliance costs and traditional and non-traditional benefits of the proposed regulation.
- **Chapter 4: Benefit Cost Analysis** – describes the benefit-cost analytic framework and utilizes the data presented in Chapter 3 to derive cost-benefit ratios for each of the six alternatives.
- **Chapter 5: Regulatory Analyses and Notices** – provides the Regulatory Flexibility Analysis, a summary of the Preliminary Environmental Assessment, the Paperwork Reduction Analysis, Executive Order 13211 Energy Analysis, and the Unfunded Mandates Analysis.

Volume II documents the detailed research conducted on pipeline mileages, costs and benefits of the proposed six regulatory alternatives. These alternatives are:

1. Apply all Part 195 to all unregulated low stress pipelines (low stress pipeline)
2. Apply all Part 195 to low stress pipeline less than 8 ⅝ inches in diameter within ½ mile of USAs
3. Apply all Part 195 to low stress pipeline 8 ⅝ inches or more in diameter outside ½ mile of USAs
4. Apply all Part 195 to low stress pipeline less than 8 ⅝ inches in diameter outside ½ mile of USAs
5. Apply Part 195 requirements except Subpart H (Corrosion Control) to all unregulated low stress pipeline
6. Apply Part 195 requirements except the Integrity Management Program to all unregulated low stress pipeline

Volume II does not further discuss the regulatory alternatives and the cost-benefit final outcomes as those are extensively discussed in Volume I. Volume II contains the following chapters:

- **Chapter 1: Introduction** – provides the organization of Volumes I and II.
- **Chapter 2: Pipelines and Pipeline Mileages** – presents estimates of impacted pipeline characteristics and mileages derived from the Phase I rulemaking, surveys of pipeline operators, and PHMSA data.

- **Chapter 3: Compliance Methods –** analyzes compliance methods and costs. It also details the different methodologies, procedures, and technologies required to comply with the Phase II rulemaking requirements. Sources of cost estimates include the Phase I rulemaking, pipeline operator surveys, industry sources, and an independent engineering assessment.

- **Chapter 4: Traditional Benefits -** quantifies the benefits associated with the rulemaking resulting from potentially avoided pipeline accidents, spills and cleanup costs. Sources examined include the Low Stress I Regulatory Analysis, studies from selected states with available data, data collected by PHMSA, and data from industry and pipeline company sources.

- **Chapter 5: Nontraditional Benefits -** quantifies the non-traditional benefits such as the benefits of standardization of regulations across all pipeline mileages, additional environmental impacts not covered by cleanup costs and increased safety, energy security, and public confidence.

2. IMPACTED PIPELINE AND PIPELINE MILEAGES

Phase II of Pipeline and Hazardous Material Safety Administration's (PHMSA) Final Rule on Protecting Unusually Sensitive Areas From Rural Onshore Hazardous Liquid Gathering Lines and Low Stress Lines (73 FR 31634), referred to as the Low Stress I Rulemaking, proposes extending safety regulations to rural low stress pipelines. Because these pipeline mileages were previously unregulated, the number of miles of pipelines that the proposed rulemaking will cover is uncertain. The purpose of this chapter is to review the available data and estimates of the potentially affected pipeline mileage.

It is difficult to develop estimates of pipeline mileage for a very specific subset of the pipeline system, such as the pipelines that will be subject to this regulation. The applicability of this set of proposed regulations to a particular pipeline depends on the location of the pipeline, the product carried, the length, the type of material the pipeline is made of, the operating pressure and other characteristics. Operators frequently build new pipelines, take existing pipelines out of service, sell or buy pipelines amongst each other, and switch the use of pipelines among products and operating pressures. Moreover, since this set of pipelines was previously unregulated, pipeline operators may have incomplete data on their assets and may not even be aware that new data collection is ongoing or applies to their systems. This chapter also examines these multiple sources of uncertainty in examining the available data.

The organization of this chapter is as follows. First, the remainder of the introduction has three parts. The first part describes the various types and categories of pipelines. This part describes how pipelines are regulated on many of their characteristics, such as their location (e.g. rural and non-rural), proximity to navigable waterways, proximity to unusually sensitive (environmental) areas, diameter, operating pressure, and classification as either gathering or transmission lines. The second part of the introduction provides a brief overview of three main sources of estimates of low stress pipeline mileage.

Section 2.1 describes the low stress pipeline mileage estimates that PHMSA developed as part of the Phase I Final Rule. Section 2.2 discusses a survey effort of pipeline operators undertaken by the Volpe National Transportation Systems Center (Volpe Center). Section 2.3 discusses the mileage estimates collected from mandatory annual reports submitted by pipeline operators to the PHMSA. Section 2.4 describes mileage estimates reported to and available from the National Pipeline Mapping System (NPMS). Section 2.5 provides a summary and conclusion on mileage subject to the Low Stress II Rulemaking and the number of operators involved.

Categories of Pipelines

CFR Part 195 Section 195.1, provided as Appendix A to this report and entitled "Which pipelines are covered by this part," provides the basic description of the categories of pipelines that hazardous liquids pipeline safety regulations cover or exempt. Three additional sections provide further clarification including:

- Section 195.11, entitled "What is a regulated rural gathering line and what requirements apply?"
- Section 195.12, entitled "What requirements apply to low stress pipelines in rural areas?"
- Section 195.2, entitled "Definitions"

These sections, provided as Appendices B through D, and PHMSA's recent regulatory actions, such as the Low Stress Phase I Regulation, have affected the mileages of pipelines subject to safety regulations and reporting requirements. The purpose of this chapter is to estimate the mileage of pipelines that the proposed rulemaking will affect. Exhibit 2-1 describes the current regulatory status of pipelines.

Exhibit 2-1: Regulatory Status of Pipelines

<table>
<tr><th rowspan="2">Nominal Diameter</th><th rowspan="2">Part 195.1 (a) covers any pipeline that:
1) Transports an HVL
2) Non-Gathering Line Operating at Stress > 20 percent SMYS
3) Crosses a Navigable Waterway
4) Gathering line in Non-Rural Area</th><th colspan="2">Rural Low Stress (Operating at Stress < 20 percent SMYS)</th><th rowspan="2">Gathering Line in a Rural Area (Operating at Stress > 20 percent SMYS)</th></tr>
<tr><th>Located within ½ mile of an USA</th><th>Located outside ½ mike of an USA</th></tr>
<tr><td>Less than 6 ⅝"</td><td rowspan="3">Regulated Previously to Phase I</td><td rowspan="2">Phase II</td><td rowspan="2">Phase II</td><td>Unregulated</td></tr>
<tr><td>From 6 ⅝" to 8 ⅝"</td><td>Regulated in Phase I</td></tr>
<tr><td>Greater or equal to 8 ⅝"</td><td>Regulated in Phase I</td><td>Phase II</td><td>Unregulated</td></tr>
<tr><td colspan="5">Part 195.1(b) exempts ten categories of pipelines including transport of a hazardous liquid (1) in a gaseous state (2) through a pipeline by gravity (3) a pipeline subject to Coast Guard regulations (4) a pipeline less than one mile long. For the other exception see Appendix A.</td></tr>
</table>

As shown in Exhibit 2-1, these proposed Phase II rulemaking would affect three major groups of pipelines:

- Pipe of less than 8 ⅝ inch nominal diameter (sometimes referred to as small diameter pipeline) within ½ mile of an USA
- Pipe of less than 8 ⅝ inch nominal diameter outside ½ mile of an USA
- Pipe of greater than or equal to 8 ⅝ inch nominal diameter outside ½ mile of an USA

Overview of Data Sources for Low Stress Pipeline Mileage

Reported estimates of the miles of energy pipelines in the U.S. vary considerably. Three important sources of estimates of low stress pipeline mileage include:

- Regulatory Analysis for Final Rule by PHMSA published in September 2007. The report is titled "Pipeline Safety: Protecting Unusually Sensitive Areas from Rural Onshore Hazardous Liquid Gathering Lines and Low Stress Pipelines." (Docket No. PSPA-2003-15864)
- A Volpe Center survey of operators of low stress pipelines. Respondents included 115 regulated companies, accounting for approximately 73 percent of the nation's total regulated hazardous liquid pipelines.
- Annual mileage data that pipeline operators report to PHMSA. Data is based on requirements promulgated as part of the Low Stress I regulation
- Mileage estimates reported to the National Pipeline Mapping System (NPMS)

The following sections examine each of these sources of pipeline mileage in detail including data collection procedures, estimating methodologies and strengths and limitation of the estimates.

2.1 Pipeline Mileage Estimates from the Phase I Rulemaking

In the Regulatory Analysis for the Final Rule published in September 2007 an estimate of low stress pipeline was developed.[1] The following paragraphs detail how the estimated mileage was determined. Exhibit 2-2 also summarizes these calculations.

According to the Final Rule Regulatory Analysis, the rural onshore low stress line mileage that the regulatory changes were affecting was unknown and therefore the regulatory analysis would have to estimate those mileages. That mileage consists of low stress pipeline with the following characteristics:

- Nominal diameter of 8 ⅝ inches or more
- Operated at a stress level of 20 percent or less of the specified minimum yield strength (SMYS) during normal operation or, if the stress level is unknown or the pipeline is not constructed using steel pipe, at a pressure of 125 pounds per square inch (psig) or less
- Located within ½ mile of an USA, as defined in 49 CFR 195

Additionally, the rule would require operators of all unregulated low stress pipelines to file annual accident and safety-related condition reports with PHMSA for those pipelines.

Development of the Low Stress Mileage Estimates

The Final Rule Regulatory Analysis used a multistep methodology to estimate low stress pipeline mileages. While the collection of additional information has superseded many of the estimates and estimating methodologies, these estimates are important because they represent a "top-down" approach to developing mileages. This type of approach is useful in that it can act as a reality check against data collected at a micro-level, especially where that data has potential for underreporting.

PHMSA began with the assumption that operators were currently using approximately 200,000 miles of hazardous liquid pipeline in the transport of petroleum and petroleum products in the U.S.[2] At the time, PHMSA's database indicated that they regulated approximately 160,000 miles of that pipeline.[3] The difference between these two numbers, 40,000 miles (200,000 - 160,000), represents the total unregulated hazardous liquid pipeline mileage in operation. According to the analysis, this unregulated mileage was primarily low stress pipelines and rural gathering lines.

The Association of Oil Pipelines (AOPL), an industry group representing pipeline operators, estimated that there were between 30,000 and 40,000 miles of gathering lines.[4] The regulatory analysis used the midpoint of AOPL's range, 35,000 miles, as the point estimate for the total number of miles of gathering lines.[5] At the time, DOT regulated the safety of approximately 2,600 miles of gathering lines.[6]

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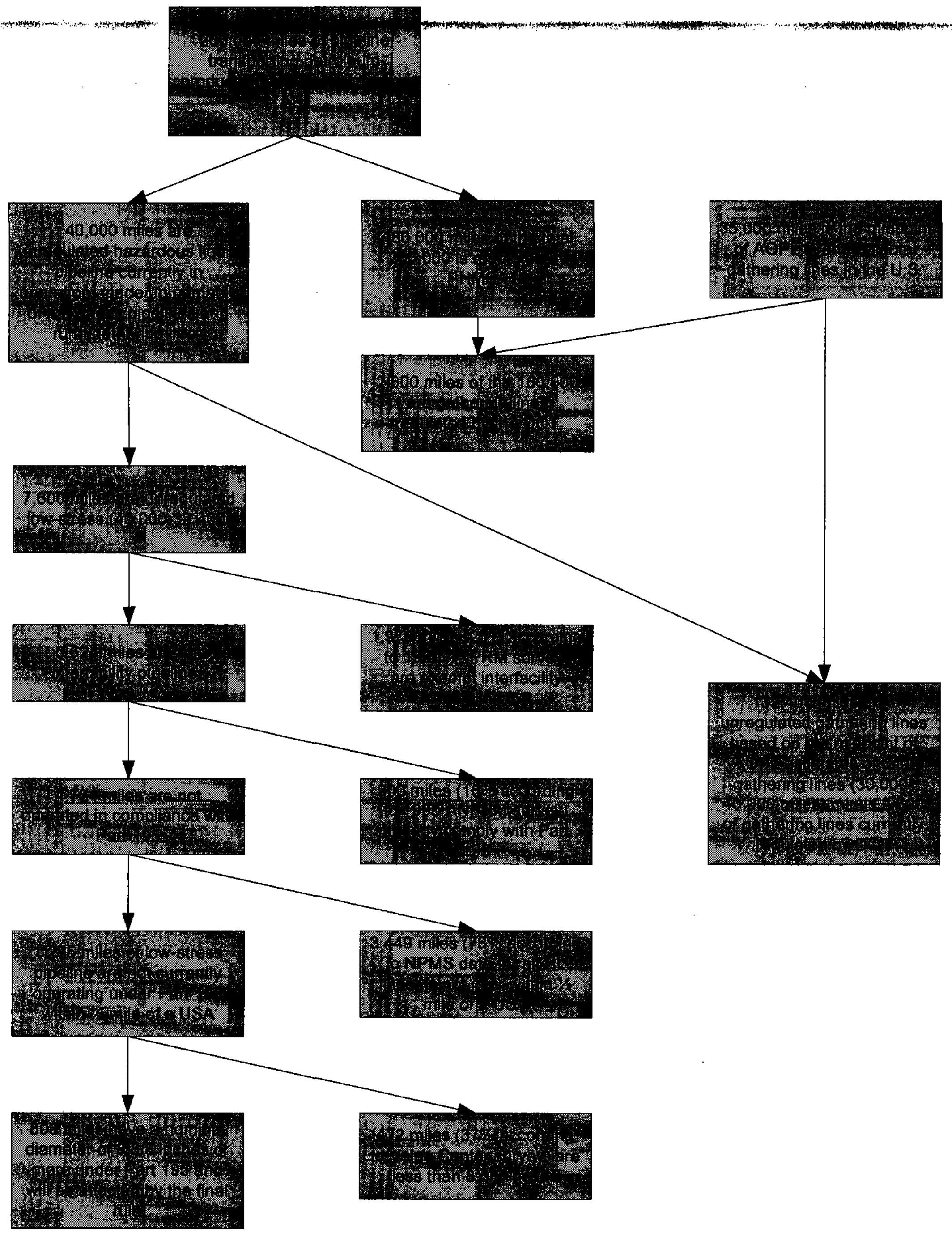
[1] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, "Pipeline Safety: Protecting Unusually Sensitive Areas from Rural Onshore Hazardous Liquid Gathering Lines and Low Stress Pipelines," Regulatory Analysis For Final Rule, September 2007, Docket No. PHSMA-2003-15864.
[2] Richard A. Rabinow, "The Liquid Pipeline Industry in the United States: Where It's Been, Where It's Going," A report prepared for the Association of Oil Pipelines, April 2004, p. 4.
[3] PHMSA, "Liquid Pipeline Operator Total National Mileage," located at http://ops.dot.gov/stats/lpo.htm.
[4] This includes the mileage of onshore and offshore crude gathering lines (see "How Many Pipelines are There?" at http://www.pipelinel01.comyOverview/energv-pl.htmn.)
[5] AOPL's estimate is for oil producing states. It might not include mileage in waters of the OCS outside of state control. Consequently, the actual rural gathering line mileage might be higher than estimated here.
[6] This includes all crude oil gathering lines subject to Part 195, including those on the OCS.

Consequently, an estimated 32,400 (35,000 - 2,600) miles of rural gathering lines were unregulated. Removing these from the 40,000 mile estimate of unregulated pipelines left 7,600 miles (40,000 - 32,400) of pipeline as the estimate for unregulated low stress lines.

Exhibit 2-2: Pipeline Mileage Estimates



The regulatory analysis noted that the final rule would affect only part of the 7,600 miles of unregulated low stress pipeline. For example, some low stress pipelines are less than one mile long and consequently not covered by the rule. A 1990 Advanced Notice of Proposed Rule Making (ANPRM) questionnaire asked participating pipeline operators about their low stress inter-facility pipelines (i.e., their low stress lines that were less than one mile long). According to the responses, approximately 26 percent of the low stress mileage of the respondents was inter-facility pipeline mileage, while approximately 74 percent was not.[7] Based on the assumption that those percentages had not changed since 1990, the analysis categorized an estimated 5,624 miles (0.74 X 7,600) of low stress pipeline as pipelines with lengths of one mile or more, while categorizing the remaining 1,976 miles as inter-facility pipelines that are less than one mile in length.

Additionally, the analysis recognized that the regulation would not affect some of the low stress mileage because it already operates in compliance with 49 CFR Part 195, even though that is not currently required. The 1990 ANPRM questionnaire asked respondents if their pipelines operated in compliance with 49 CFR Part 195. According to the responses, operators complied with 49 CFR Part 195 for approximately 16 percent of their low stress pipeline mileage, while approximately 84 percent did not.[8] Based on the assumption that those percentages had not changed since 1990, an estimated 4,724 miles (0.84 x 5,624) of low stress pipeline were estimated not to be operated in compliance with 49 CFR Part 195.

To complete the estimate of the low stress pipeline mileage impacted by the regulatory changes in the final rule, the analysis used information on the proximity of low stress pipelines to USAs. According to information from the National Pipeline Mapping System, approximately 27 percent of all regulated hazardous liquid pipeline mileage is within ½ mile of an USA.[9] Therefore, PHMSA assumed that 27 percent of the 4,724 miles of low stress pipeline that was not currently operating in compliance with 49 CFR Part 195 was within ½ mile of an USA. That is, PHMSA assumes that 1,275 miles (4,724 x 0.27) of low stress pipeline not currently operating under 49 CFR Part 195 is within ½ mile of an USA.

The final rule would only bring low stress pipelines with a nominal diameter of 8 ⅝ inches or more into compliance with 49 CFR Part 195. PHMSA estimated that 63 percent of all low stress pipelines have a diameter of 8 ⅝ inches or more. Thus, the analysis estimated that the Phase I final rule would affect approximately 803 miles of low stress pipeline.[10] The analysis estimated that an additional 3,921 miles of additional low stress mileage would be subject to Part 195(a) (6), which required that operators file annual accident and safety-related condition reports. This mileage is the subject of the proposed regulations. Exhibit 2-3 summarizes the estimates of affected mileages.

Exhibit 2-3: Summary of Impacted Mileage from the Low Stress I Regulatory Analysis

Category	Mileage Specification	Miles
Rural Gathering Lines	Gathering line mileage impacted	599
Rural Low Stress Pipelines	Low stress mileage brought under 49 CFR Part 195 safety requirements	803
	Additional low stress mileage for which annual, accident, and safety-related condition reports must be filed	3,921

[7] Pipeline and Hazardous Materials Safety Administration (PHMSA), "Protecting Unusually Sensitive Areas From Rural Onshore Hazardous Liquid Gathering Lines and Low Stress Lines: Final Rule," PHMSA-RSPA- 2003-15864, Federal Register, Vol.73, June 3, 2008.
[8] For more detail on this, see p. 8 of "Economic Evaluation of Regulating Certain Hazardous Liquid Pipelines Operating at 20 Percent or Less of Specified Minimum Yield Strength," July 21, 1992, which can be found in Docket RSPA-2003-15864.
[9] Communication from Amy Nelson, PHMSA, March 13, 2007.
[10] Preliminary results from the pre-test of an industry-wide survey of low stress pipelines, Volpe Center for PHMSA, 2007.

Limitations of the Data

A "top-down" approach to developing mileages is useful in that it can act as a reality check against data collected at a micro-level, especially where that data has potential for underreporting. However, the analysis should use this data only as a general guide. For example, early in the analysis the midpoints of an AOPL estimate of 30,000 and 40,000 miles of gathering lines is used. This introduces a range of uncertainty larger than the final estimates. In addition, data from a 1990 survey is also used. Observers should apply scrutiny to percentages derived from this dated information.

2.2 Pipeline Mileage Estimates from the Volpe Center Survey

Under the PIPES Act, all low stress hazardous liquid transmission pipelines are subject to the same standards and regulations as other hazardous liquid transmission pipelines with limited exceptions. Historically, federal safety regulations have not regulated pipelines operating at low stress in rural areas. Therefore, the extent of these types of pipelines is unclear due to a lack of available and consistent data. In order to address this data gap, PHMSA and the Volpe National Transportation Systems Center (Volpe Center)[11], conducted two sets of information collection on rural hazardous liquid low stress pipeline.

The Original Volpe Center Survey

From August 4 to September 19, 2008, PHMSA and Volpe Center conducted the first set of what PHMSA officials originally envisioned as a one-time information collection of rural hazardous liquid low stress pipeline. The objective of the "Rural Low Stress Hazardous Liquid Pipelines Survey" was to provide PHMSA better information about the number of miles of rural hazardous liquid low stress pipeline. The survey requested companies operating hazardous liquid pipelines to report on:

- Pipeline mileage: total number of low stress pipeline miles
- Rural low stress pipeline characteristics: specific information on interplant pipeline miles, mileage of low stress pipeline having a diameter equal to or greater than 8 ⅝ inches, mileage of steel low stress pipeline, and mileage of non-metallic low stress pipeline
- Pipeline products: listing of all products transported using rural low stress pipeline
- Pipeline location by state: listing of states with low stress pipeline and corresponding mileages
- Unusually sensitive areas: total number of low stress pipeline miles within ½ mile of an USA
- Breakout tanks: total number of breakout tanks associated with the low stress pipeline miles

The Volpe Center expected two "population groups" to respond to the survey: (1) a population of companies with previously regulated pipelines and (2) a population of companies that operate unregulated lines exclusively, which might include unregulated rural low stress pipeline. Based on data collected by PHMSA from entities that operate regulated hazardous liquids pipelines, the Volpe Center estimated that approximately 288 companies operate low stress pipeline.

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[11] The John A. Volpe National Transportation Systems Center in Cambridge, Massachusetts, is a center of transportation and logistics expertise, operating under the United States Department of Transportation.

State and Company Follow-up Survey

The Volpe Center conducted an additional survey between February 11, 2009 and March 27, 2009 as a follow up to the previous survey of unregulated low stress pipelines. The follow-up survey collected additional information including:

- Incident information for the low stress pipeline
- Rate at which reported low stress pipeline are voluntarily operated in accordance with Part 195
- Cost data for complying with portions of Part 195

In order to collect these data, the survey targeted the following groups:

- The nine companies reporting the most low stress pipeline mileage in the low stress pipeline survey
- State pipeline regulatory agencies in the nine states in which the most low stress pipeline mileage was reported in PHMSA's low stress pipeline survey

This survey did not collect data on pipeline mileage and therefore the analysis of pipeline miles does not make extensive use of this survey. However, one of the respondents, MarkWest, reported in their answers that their system consists of approximately 100 miles of trunk line and approximately 142 miles of gathering lines. Since gathering lines are not subject to this regulation, this survey response was used to adjust the reported Volpe Center results.

Survey Results

Respondents to the survey included 115 regulated companies, which accounted for approximately 73 percent, or about 120,905 miles, of the Nation's total regulated hazardous liquid pipeline mileage. In addition, eleven additional companies not on the list of the 2006 PHMSA annual report filers responded.

Exhibit 2-4 summarizes the results of the survey. In total, operators reported 1,233 miles of low stress pipeline. Nineteen companies operate these pipelines, with three companies operating 52 percent (645 miles) of the total low stress pipeline miles. Mileage responses for those operating low stress pipelines ranged from 1 mile to 242 miles.

Exhibit 2-4: Volpe Center Rural Low Stress Pipeline Survey Response Summary

Survey Variable	Reported Mileage (Rounded to Nearest Mile)	Percent of Total Rural low stress pipeline
Total number of miles of rural low stress pipeline (including interplant pipelines < 1 mile)	1,233	100
Number of interplant pipelines less than 1 mile in length	83	7
Number of miles with a nominal diameter of 8 ⅝ inches or greater	753	61
Number of miles of steel pipe pipeline	1,016	82
Number of miles of non-metallic pipe pipeline	1	0.08
Total number of miles of rural low stress pipeline operated within 1/2 mile of unusually sensitive area	228	18
Number of breakout tanks associated with total number of rural low stress pipeline reported	42	3
Products transported using low stress pipeline	Amine, Benzene, CO2, Condensate, Crude Oil, Ethane, Ethylene, Kerosene, Methanol, NGL, Propane, RPP, Xylene, and "other commodities"	
Note: Except for "Products transported using low stress pipeline," this table and following section exclude data provided by the two companies, which did not file a 2006 annual report, which reported having low stress pipelines (total of 5.23 miles).		

Approximately seven percent (83 miles) of the reported low stress pipeline miles are interplant pipelines less than one mile in length. Sixty-one percent (753 miles) of the reported low stress pipeline miles have a nominal diameter of 8 ⅝ inches or greater. Eighty-two percent (1,016 miles) of the reported low stress pipeline is steel pipe pipeline, with one company reporting one mile of non-metallic pipe. The steel pipe mileage estimate of 1,016 miles and the non-metallic pipe mileage estimate of one mile do not equal the total low stress pipeline reported, which is 1,233 miles. The difference, 216 miles, is either due to incomplete information provided by some respondents or the presence of metallic pipe, made of materials other than steel. According to the operators, 18 percent (228 miles) of the reported low stress pipeline is within ½ mile of an USA.

The Volpe Center report used the survey data to develop estimates of total U.S low stress mileage, as well as mileages of pipe 8 ⅝" inches or greater in diameter and mileages of pipe 8 ⅝" inches or greater in diameter and within ½ mile of an USA. Exhibit 2-5 summarizes these estimates. The shaded cells provide the results of each calculation and the cell below each shaded cell provides the details of the calculation.

Exhibit 2-5: Volpe Center Rural Low Stress Pipeline Estimates Summary

Total US Mileage Estimate = 1,575 Miles
• 1,233 reported miles – 83 interplant = 1,150 miles • 1,150 miles/120,905 regulated miles of responders = 0.0095 • 165,624 total regulated miles – 120,905 regulated miles of responders = 44,719 miles • 44,719 miles * 0.0095 = 425 estimated additional low stress pipeline miles • 425 estimated additional miles + 1,150 known miles = 1,575 miles
Mileage 8 ⅝" Inches or Greater in Diameter = 1,040
• 754 of 1,150 miles, or 65.5 percent reported to have a diameter of 8 ⅝ inches or greater • 0.66 * 1,575 = 1,040
Mileage 8 ⅝" Inches or Greater in Diameter within ½ mile of an USA = 312
• 228 of the 754 miles with a diameter of 8 ⅝" inches or greater, or 30 percent, were within ½ mile of an USA • 0.30 * 1,040 = 312 • Companies are not expected to have USA-proximity data for its smaller diameter low stress pipeline

The U.S. total estimate of 1,575 miles begins with the total reported miles and subtracts interplant pipelines of less than one mile in length, as these pipelines are exempt from regulation. The remaining calculations expand the mileage to account for non-respondents. Pipeline mileage estimates of pipe 8 ⅝" inches or greater in diameter reported in the survey are applied to the U.S. total estimate. Mileages of pipe 8 ⅝" inches or greater in diameter and within ½ mile of an USA applies the percentage of such pipe reported in the survey to mileages of pipe 8 ⅝" inches or greater in diameter, but assumes companies do not have USA-proximity data for small diameter low stress pipeline.

Survey Results Limitations

First, the survey results are subject to several uncertainties. A total of 173 companies in the known population did not respond to the survey. It is unknown whether these non-respondents did not respond because they did not have any low stress pipeline mileage or whether they just chose not to respond. It is certainly likely that companies with significant low stress pipeline mileage were more likely to respond and therefore potential response bias makes it difficult to calculate low stress pipeline mileage estimates with certainty. The Volpe Center estimates do not allow for any non-response bias. This is a conservative assumption, resulting in a higher estimate of mileage.

Second, the data collection methodology may under-represent companies that operate unregulated lines exclusively, which might include unregulated rural low stress pipeline. At the time of the survey, PHMSA did not collect data on these operators and it would have required a significant research effort to compile a list of such companies. According to the Volpe Center report, industry experts have indicated that the number of operators who operate unregulated lines exclusively is expected to be small, so according to the Volpe Center report, the potential under-representation of this population was assumed to have little, if any, effect on results. Additionally, this population was not "excluded" from the survey. By posting the survey in the Federal Registry and provision of the survey via e-mail newsletters of industry associations, the Volpe Center assumes most operators would have adequate notification of the survey and could complete it within the response period.

Third, there appears to be a reasonable possibility that the classification of pipelines causes significant difficulty in accounting for pipeline mileage for specific subgroups. The applicability of regulations to pipeline mileage is dependent on a number of physical characteristics of the pipeline as well as the geography over which it travels. Factors that affect the regulatory status of pipeline mileage include:

- Length: low stress pipeline less than one mile long measured outside facility grounds are not covered
- Diameter: the regulations treat pipelines of different diameters differently. For example, the Low Stress I rulemaking only applied to pipeline mileage with diameters of greater than 8 ⅝ inches. For gathering lines, the application of regulatory requirements also varies according to diameter
- Operating pressure: the applicability of regulatory provisions vary according to operating pressure with different regulatory requirements for pipelines operating at less than 20 percent of specified minimum yield strength (SMYS)
- Location: the applicability of regulatory provisions vary according whether a pipeline is outside ½ mile of an USA, is onshore or offshore, is in a rural area, or crosses a navigable waterway
- Use: pipelines of different purposes, particularly gathering lines, are subject to different regulatory requirements

The difficulty inherent in classifying mileage may lead to companies reporting conflicting and potentially erroneous data. For example, on the Volpe Center survey, the MarkWest Michigan Pipeline reported 242 low stress pipeline miles, but also stated that 142 of these miles were gathering lines, which the survey instructions specifically asked operators to exclude.

The Volpe Center estimates distribute pipe with diameter of 8 ⅝ inches or greater in equal proportions both inside and outside ½ mile of an USA. However, the Volpe Center assumes all reported small diameter pipe is within ½ mile of an USA. The Volpe Center states, "Companies are not expected to have USA-proximity data for its smaller diameter low stress pipeline."[12]

Estimates of Mileages Affected by the Proposed Regulations

Exhibit 2-6 provides mileage estimates by pipeline diameter and USA proximity based on the Volpe Center survey data. These estimates start with the total US estimate of 1,575 pipeline miles and are distributed by pipeline diameter and USA proximity based on Volpe Center data. The results shown in bold text would be subject to the proposed Phase II regulation. The estimate of total affected miles is 1,384.3.

Exhibit 2-6: Pipeline Mileage Estimates by Diameter and USA Status

Pipeline Diameter	Percent by Diameter	Miles Inside USA	Miles Outside USA	Total
Percent Inside/Outside USA		18.5%	81.5%	100.0%
Less Than 8 5/8"	34.5%	**100.5**	**443.2**	543.7
Greater or Equal to 8 5/8"	65.5%	190.7	**840.6**	1,031.3
Total	100.0%	291.2	1,283.8	1,575.0
Bolded miles are subject to the Low-Stress Phase II proposed regulations =				**1,384.3**

Source: Volpe Center Survey

[12] Volpe Center "Rural Low Stress Hazardous Liquid Pipelines Survey, Summary of Results Including Late Responders." Transmitted from Carson Poe of the Volpe Center to Cheryl Whetsel of PHMSA on July 27, 2009 9:54 am Eastern.

2.3 Pipeline Mileage Estimates from Collected Annual Reports

PHMSA has collected and published annual records of the mileage of regulated pipelines since 1984. Pipeline operators are required to report the mileage of their regulated pipeline networks to PHSMA annually. Exhibit 2-7 summarizes the latest published annually reported pipeline mileage data for Hazardous Liquid and Carbon Dioxide Systems. The PHMSA website also summarizes data by system type with separate data for the following products:

- CO_2 or other
- Crude oil
- Highly volatile liquid (HVL)
- Petroleum & refined products

Exhibit 2-7: PHMSA Mileage for Hazardous Liquid and Carbon Dioxide Systems

Year	No. of Records	Onshore	Offshore	Total
2004	415	161,715	5,092	166,806
2005	437	161,586	5,081	166,667
2006	443	161,519	4,962	166,481
2007	463	165,620	5,185	170,805
2008	457	168,501	5,023	173,524

Source: PHSMA website[13]

PHMSA's decision to regulate rural low stress pipelines in two phases was due at least in part to a decision by the agency to regulate immediately the larger pipe in the most environmentally sensitive areas while simultaneously collecting more data on rural low stress pipeline mileage. As a result, the Phase I regulation included a revision of 49 CFR Part 195 that added 195.1 (a) (6), which requires that rural low stress pipeline operators file annual accident and safety-related condition reports.[14] Consequently, 2008 marked the first year operators were required to report the mileage of rural low stress pipelines both unregulated and newly regulated.

The expectation was that the total mileage of low stress pipelines reported by operators would increase rather dramatically from 2007 to 2008 because of the new requirement in 195.1 (a) (6). However, this was not the case. Exhibit 2-8 summarizes the low stress mileage reported to PHMSA for 2007 and 2008. The first third of the exhibit reports the total mileage reported including HVL mileage. The increase was only about 40 miles.

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[13] PHMSA, Natural Gas Transmission, Gas Distribution, and Hazardous Liquid Annual Mileage: Annual Mileage for Hazardous Liquid or Carbon Dioxide Systems. 11/1/09.
http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=036b52edc3c3e110VgnVCM1000001ecb7898RCRD&vgnextchannel=bc79c0124500d110VgnVCM1000009ed07898RCRD&vgnextfmt=print

[14] See 49 CFR Part 195.1 (a) (6) that now states that "For purposes of the reporting requirements in subpart B, a rural low stress pipeline of any diameter." For the full text of 195.1, see Appendix A.

Exhibit 2-8: PHMSA Low Stress II Pipeline Mileage Estimates for 2007 and 2008

	Number of Operators	2007 Miles	2008 Miles	Change +/-
Low-Stress Miles Including HVLs				
Operators Reporting Less Mileage in 2008	41	3,132.580	990.235	-2,142.345
Operators Reporting Identical Mileage in 2007 and 2008	99	1,324.697	1,324.697	-
Operators Reporting More Mileage in 2008	44	1,079.568	3,262.053	2,182.485
Total	**184**	**5,536.845**	**5,576.985**	**40.140**
Low-Stress Miles Not Including HVLs				
Operators Reporting Less Mileage in 2008	38	2,513.345	948.289	-1,565.056
Operators Reporting Identical Mileage in 2007 and 2008	81	1,030.468	1,030.468	-
Operators Reporting More Mileage in 2008	35	954.686	2,838.299	1,883.613
Total	**154**	**4,498.499**	**4,817.056**	**318.557**
Low-Stress Miles Not Including HVLs (Similar Named Operators Combined)				
Operators Reporting Less Mileage in 2008	30	2,684.794	1,467.508	-1,217.286
Operators Reporting Identical Mileage in 2007 and 2008	65	949.904	949.904	-
Operators Reporting More Mileage in 2008	23	863.801	2,399.644	1,535.843
Total	**118**	**4,498.499**	**4,817.056**	**318.557**

The initial conclusion was that operators misunderstood the new requirements perhaps believing that operators were not supposed to report these new mileages until the 2009 annual report. However, a more detailed examination of the data reveals that there was actually quite a large amount of newly reported low stress pipeline mileage. For all low stress pipeline miles including HVLs, 41 operators reported 2,142 less miles in 2008 than in 2007, 99 operators reported the exact same mileage, and 44 operators reported 2,182 more miles.

The middle third of the exhibit presents similar information, except the analysis excludes HVL mileage as this mileage is already subject to Part 195 regardless of operating stress and therefore is not subject to the proposed rulemaking. For this mileage, the exhibit shows an overall increase of 319 miles in the latest annual reports. Once again, the data indicate a substantial decrease in mileage reported by some operators and a substantial increase by others.

One possibility for the mileage variability is operators may switch assets from one subsidiary of a parent company to another or sold assets to other operators. Analysis of the data uncovered several cases of this type of activity. For example, "San Antonio Pipeline L.P." reported 14 miles of low stress pipe in 2007, but made no report in 2008. Meanwhile, "San Antonio Pipeline Corporation" made no report in 2007, but reported 14 miles in 2008. To account for this possibility, the analysis was amended to combine like name companies. In addition, for each operator who reported less mileage in 2008, an analysis was conducted that crosschecked the difference among the operators with dissimilar names reporting more miles. The analysis did not identify any potential transfers of assets.

The bottom third of the exhibit reports the data with similar named operators combined. Again, HVL mileage is not included in the data. The affect of combining the operators is to reduce the number of operators reporting and the number of delisted and newly listed miles. However, there is still a net increase of 319 miles and 23 operators reporting 1,536 new low stress miles.

One of the major limitations of the PHMSA mileage data is the inability to sort pipeline mileage data by pipeline attributes. While each operator reports low stress mileage and HCA mileage, data is not available on the extent to which the low stress miles are inside or outside an HCA. This is understandable given the additional reporting burden that PHMSA would have to impose on operators. However, the unavailability of mileage by detailed characteristics is a major obstacle in calculating incident frequencies.

2.4 National Pipeline Mapping System (NPMS) Mileage Data

The National Pipeline Mapping System (NPMS) data consists of gas transmission pipelines and hazardous liquid trunk lines. It does not contain gathering or distribution pipelines, such as lines that deliver gas to a customer's home. If the hazardous liquid pipeline has a nominal diameter of greater than 8.625 inches and operates at 20 percent or less of SMYS, operators are required to submit data to the NPMS. If the liquid low stress pipeline has a nominal diameter of less than 8.625 inches, operators are not required to submit data to the NPMS. However, based upon discussions with a limited sampling of operators that submitted data to the Volpe Center survey on low stress pipelines, there is a general impression that such operators for presently unregulated (Phase II) low stress pipelines have generally submitted such information to NPMS.

While the NPMS has created a map of all the rural low stress pipelines across the United States, this map cannot be included in this report due to national security concerns. However, Exhibit 2-9 summarizes county-level data aggregated to the state-level on low stress pipelines mileage excluding:

- HVL lines
- Pipelines within "highly populated areas" or "other populated areas"
- Pipelines that are both greater than 8.625 inch diameter and within ½ mile of an USA
- Pipeline mileages with a county definition of "offshore"

Exhibit 2-9: NPMS Rural Low Stress Pipelines Mileage per State

State	Mileage	State	Mileage
AK	12.4	MO	0.5
Al	13.5	MS	77.1
AR	4.2	MT	324.2
AZ	1.6	ND	0.6
CA	43.4	NJ	0.5
CO	9.5	NM	41.5
CT	0.2	NV	1.0
FL	3.8	NY	0.1
GA	10.0	OH	201.9
IL	56.8	OK	38.5
IN	9.8	PA	1.2
KS	24.0	TX	312.2
KY	0.6	VA	0.2
LA	6.1	WA	3.1
MD	0.1	WV	7.7
MI	7.9	WY	432.7
MN	0.9	**Total**	**1672.9**

Prior to this year, the NPMS could not differentiate low stress mileage because the NPMS did not collect operating pressure. NPMS staff could not tell whether low stress liquid operators were submitting to

NPMS before the Low Stress I Rulemaking. Since PHMSA published the rule, the NPMS added a low stress field to the dataset for operators to fill out.[15]

Limitations

PHMSA created a new field for operators to indicate whether a reported pipeline segment is low stress. However, this is the first time the NPMS introduced this field. An engineer for this study team noted a pipeline segment for which he had participated in the design and construction was not a low stress pipeline, but had been identified as a low stress pipeline.

2.5 Summary and Conclusion

This chapter has reviewed four sources of data that provide varying levels of detail, information and data on low stress pipeline mileages. Each source of data has limitations. This may be partially because this is the first time PHMSA asked operators to report mileage information for these unregulated pipeline segments. For example, PHMSA collected the Volpe Center survey data on a one-time voluntary basis. Both the PHMSA Annual Report and NPMS data collected data on these segments for the first time. In fact, detailed examination of some of the mileages reported by individual operators has raised questions as to their accuracy. It appears that some operators have difficulty identifying unregulated non-HVL low stress pipelines. However, this analysis has not removed any questionable mileage from the estimates, as it might create a downward bias.

In analyzing the data, the first step was to examine the overall level of mileages eligible for Phase II low stress pipelines. There was a consensus among three of the four data sources that the mileage was somewhere in the range of 1,500 miles. For example, the Volpe Center estimates 1,575 miles, including miles subject to Phase I and excluding intra-plant miles. This estimate drops to 1,384.3 with miles subject to Phase I excluded. The NPMS reports 1672.9 miles, excluding intra-plant and low stress lines regulated in Phase I. The PHMSA annual report database includes 1,536 newly reported low stress pipeline miles. The top-down estimates included in the Phase I Regulatory Analysis appears to have been a high-end estimate of low stress pipeline mileage at 5,624 miles. Thus, the remainder of this regulatory analysis relies on this consensus of the other three data sources.

Since the Volpe Center data includes a variety of other information used in this analysis including characteristics of the reported mileage, this regulatory analysis relies on that data source for Phase II LSP mileage estimates. This analysis assumes the miles subject to the proposed regulation are as follows (as shown in Exhibit 3-5):

- Pipe of less than 8 ⅝ inch nominal diameter within ½ mile of an USA = 100.5 miles
- Pipe of less than 8 ⅝ inch nominal diameter outside ½ mile of an USA = 443.2 miles
- Pipe of greater than or equal to 8 ⅝ inch nominal diameter outside ½ mile of an USA = 840.6 miles

[15] Email correspondence from NPMS staff received Thursday, October 29, 2009 at 10:27 AM.

3. PHASE II COMPLIANCE COSTS

In order to develop comprehensive analysis of the compliance costs associated with the proposed rulemaking, this regulatory evaluation includes a review of cost data developed in recent PHMSA rulemakings, and an analysis of the various compliance procedures, methodologies, and technologies that operators may need to adopt to come into compliance. This chapter consists of the following subsections:

- **Section 3.1** includes a summary of compliance cost categories, data sources and resulting dollar estimates published in the Phase I Regulatory Analysis.
- **Section 3.2** provides the cost data based on a Volpe Center survey of major pipeline operators.
- **Section 3.3** outlines the compliance methodologies and costs based on an independent engineering assessment for pipeline operators to comply with Phase II regulations.
- **Section 3.4** provides the chapter summary and conclusion.

This chapter presents the estimated cost of compliance with the proposed rulemaking. These cost data, which were developed by an independent engineering firm, incorporate information collected through a PHMSA industry survey, interviews with vendors and pipeline operators, and industry trade catalogues and price lists.

3.1 Phase I Rulemaking Estimates of Compliance Costs

The following presents a summary of the methodology, key data sources, and resulting compliance cost estimates developed by PHMSA for regulations affecting operators of rural onshore hazardous gathering lines and low stress lines completed under Phase I. PHMSA's Regulatory Analysis, published September 2007 (Docket No. RSPA-2003-15864) identifies the following compliance cost categories:

- Determining if pipelines are within one mile of an USA
- Implementing corrosion control for steel pipes and continuously monitoring pipelines to identify any changes that could necessitate cleaning the lines and accelerating the corrosion control program
- Installing and maintaining pipeline line markers
- Implementing damage prevention programs
- Implementing a public education program
- Establishing a maximum operating pressure (MOP) for steel pipes
- Reporting accidents and safety-related conditions and developing annual reports
- Meeting design, construction, and testing requirements for steel gathering lines constructed, replaced, relocated, or otherwise changed
- Meeting drug and alcohol testing requirements
- Demonstrating operator qualification (OQ) compliance
- Establishing an assessment integrity program (low stress pipelines only)
- Establishing a leak detection program (low stress pipelines only)

Pipeline Proximity to an USA

To determine the proposed rule's applicability to pipelines, operators must determine the:

- Nominal diameter of their pipelines
- SMYS (or, alternatively, the operating pressure) of their pipelines
- Whether the distance from their lines to the nearest USA is 0.25 miles or less

The Independent Petroleum Association of America estimated it would cost approximately $500 per mile (2003 dollars) to perform the surveys needed to comply regulations related to defining regulated onshore gas gathering lines and an additional $100 per mile for periodic surveys to monitor changes. PHMSA estimated that it would cost $105 per pipeline mile (= $100 per pipeline mile converted from 2003 dollars to 2005 dollars) to perform the initial screening and an additional $105 per mile to conduct future determinations.

Corrosion Control & Monitoring Systems

The proposed regulation establishes corrosion control and monitoring requirements for onshore steel gathering and low stress pipelines. PHMSA assumes that the 80 percent of affected gathering line and 90 percent of low stress pipeline operators already have corrosion control as a normal part of operations and would not incur costs to install such protection as a result of this proposed rulemaking. Using data provided by the Independent Petroleum Association of American (IPAA), initial corrosion control compliance costs were estimated to be $14,615 per mile (2003 dollars) for initial corrosion control mechanisms and $382 per mile annually (2003 dollars). Converting 2003 to 2005 dollars, PHMSA estimated compliance cost for the initial cost of corrosion control for gathering and low stress lines is estimated to be $15,022 per mile and the annual cost of corrosion control for impacted lines is also estimated to be $393 per mile.

Installing and Maintaining Pipeline Line Markers

Compliance costs for line markers include initial installation and annual maintenance. PHMSA estimates that the costs of installation and maintenance are approximately $50 per marker (2003 dollars). The IPAA estimated that 10 markers are needed per mile of pipeline. As a result, PHMSA concludes that installation of line markers for both gathering and low stress lines is $514 per mile (2005 dollars). IPAA estimated annual surveying and monitoring of line marker condition would costs $80 per mile (2003 dollars). It further estimated that 10 percent of the markers must be replaced annually. As a result, PHMSA estimates line marker maintenance would cost $134 per mile (2005 dollars) annually. Note, PHMSA concludes that only 10 percent of new pipelines miles would become regulated under the proposed rule due to existing industry standards for hazardous material pipelines.

Implementing Damage Prevention Programs

To prevent damage caused by accidental excavation, the majority of operators participate in "One Call Programs." These programs consist of centralized notification centers that can be called by any member of the public preparing to conduct digging or excavation. Pipeline operators screen the calls to determine if a proposed excavation is close to the pipeline. Program costs vary due to the number of calls or tickets that an operator experiences annually. The IPPA estimated gathering pipeline operators would experience 20 call tickets per mile annually. The cost is $1 per ticket (2003 dollars). The cost to screen and locate pipeline was estimated to be $10 per ticket (2003 dollars). According to the regulatory analysis, IPAA estimated that the total annual cost per mile of implementing a damage prevention program was $220 (2003 dollars). PHMSA assumed that the total annual cost per mile would be $226 (2005 dollars).

Note that Colorado and Kansas have no existing requirement to participate in a one-call program. Oklahoma does have a requirement, but it does not apply to all pipeline operators. As a result, PHMSA assumes that 25 percent of affected pipeline that would be impacted are located in Oklahoma, Colorado, and Kansas.

Establishing a Maximum Operating Pressure (MOP) for Steel Pipes

Establishing and monitoring maximum operating pressure for steel pipes does not involve additional pipeline installation or configuration since operators can analyze existing records of pipeline records. Therefore, PHMSA does not associate major compliance costs with this requirement.

Reporting Accidents and Safety-Related Conditions and Making Annual Reports

The proposed regulation requires operators of rural onshore gathering and low stress lines to report spills. Operators are also required to file annual reports detailing their pipe inventory and any leaks repaired.

PHMSA estimates that the costs of this reporting requirement are minimal. The agency assumes that this data is readily available as part of good business practices. Furthermore, PHMSA states that annual incident reporting is already a requirement for large major pipeline operators.

Meeting Design, Construction, and Testing Requirements

The costs associated with meeting design, construction, and testing requirements for new steel lines construction and existing steel lines replacement, relocation, or alteration are unknown. However, due to existing design, construction, and testing practices in the hazardous pipeline industry and other proposed regulations (ASME B31.4), PHMSA assumes the cost of compliance is $0.

Meeting Drug and Alcohol Testing Requirements

Operators of rural onshore gathering and low stress lines would be subject to drug and alcohol testing requirements. The costs of this program would include: (1) the cost of developing a testing plan, (2) the costs of testing; (3) the costs of recordkeeping associated with the testing; and (4) the costs of reporting. However, PHMSA assumes that the costs of compliance are minimal due to the existence of these programs across the pipeline industry. The cost to implement these programs to rural and low stress line operators is negligible.

Demonstrating Operator Qualification (OQ) Compliance

Impacted line operators would be required to detail the processes used to determine the qualification of persons performing certain operations and maintenance tasks. PHMSA states that OQ is virtually industry standard. Therefore, the cost of compliance would be nominal.

Integrity Assessment Program

The proposed rule requires affected operators to establish an integrity assessment program using in-line inspection tools, direct assessment, pressure testing, or other tools to evaluate the integrity of the regulated pipeline segments. Estimates of the costs associated with the three leading assessment method (in-line inspection, hydrostatic testing, and direct assessment) were based on a cost of corrosion study entitled, "Gas and Liquid Transmission Pipelines" prepared by Neil Thompson for the Federal Highway Administration.

Exhibit 3-1: Pipeline Inspection Costs per Mile (1998 Dollars)

Cost Category	High Estimate	Low Estimate
In-Line Inspection:		
• Line Preparation	$27,300	$6,800
• Inspection	$3,500	$2,000
Hydrostatic Testing:		
• Line Preparation	$5,000	$1,250
• Testing	$92,160	$27,650
Direct Assessment:		
• Line Preparation	$0	$0
• Assessment	$6,000	$2,000

Key assumptions applied by PHMSA to the total costs of compliance identified above are as follows:

- 50 percent of affected mileage (342 = 684 / 2 miles) will be periodically evaluated using the lowest cost procedure, direct assessment, while the remaining 50 percent of the mileage would be periodically evaluated using in-line inspection.
- Cost per mile to perform direct assessment will be $4,649 (= $4,000 – the mid-point of the $2,000 to $6,000 range – converted from 1998 dollars to 2005 dollars).
- Cost per mile to prepare a line for in-line inspection would be $19,535 (= $17,050 – the mid-point of the $6,800 to $27,300 range – converted from 1998 to 2005 dollars), while the cost per mile to perform in-line inspection will be $3,084 (= $2,750 – the mid-point of the $2,000 to $3,500 range – converted from 1998 to 2005 dollars).
- Impacted pipelines would be assessed once every 6 years.

Leak Detection Programs

Operators would be required to establish a leak detection program for the regulated portions of their lines. It is assumed that most pipeline operators comply with existing regulations and adopt industry practices and standards with respect to leak detection. As a result, the cost of compliance is assumed to be $0.

Summary of Compliance Cost Ranges

The table below presents a summary of the one-time and reoccurring compliance cost per pipeline mile associated with proposed rule. Implementing corrosion control measures presents the highest per mile cost at $15,022. Compliance with all other requirements such as establishing pipeline proximity to USAs and line markers ranges between $105 and $514 per mile.

Exhibit 3-2: Summary of Compliance Costs
(PHMSA 2007 Regulatory Analysis)

Cost Component	Unit Cost per Mile		Additional Costs (In thousands of dollars)		
	Initial Costs	Recurring Costs	Year 1	Years 2 through 6	Years 7 and on
Proximity to a USA	$105	$0	$135	$0	$0
Corrosion Control	$15,022	$393	$2,824	$74	$74
Line Markers	$514	$134	$66	$17	$17
Damage Prevention	$226*	$226	$73*	$73	$73
Public Education	$173*	$173	$222*	$222	$222
MOP	NA	Negligible	$0	$0	$0
Reporting	NA	Negligible	$0	$0	$0
Pipeline Design, Construction, and Testing	$0	$0	$0	$0	$0
Drug and Alcohol Testing	$0	Negligible	$0	$0	$0
Operator Qualification	Negligible	Negligible	$0	$0	$0
Integrity Assessment Program	Various*†	Various††	$1,554*	$1,554**	$441
Leak Detection Program	$0	$0	$0	$0	$0
Total			$4,874	$1,940	$827

Notes: NA = Not applicable
* = Recurring costs will be incurred in the initial year, as well as in all subsequent years.
** = Initial costs will be incurred in the second through sixth years, as well as in the initial year.
† = $0 for operators choosing direct assessment, $19,535 for operators choosing in-line inspection.
†† = $4,649 for operators choosing direct assessment, $3,084 for operators choosing in-line inspection.

3.2 Volpe Center Survey Estimates of Compliance Costs

PHMSA Industry Survey Results

In July 2008, the PHMSA's Office of Pipeline Safety (OPS) transmitted a request to operators of rural low stress hazardous liquid pipelines to complete a voluntary survey that solicited information on the following:

- Total number of low stress pipeline (low stress pipeline) miles.
- Number of rural interplant pipeline miles, mileage of low stress pipeline having a diameter equal to or greater than 8 ⅝th inches, mileage of steel low stress pipeline, and mileage of non-metallic low stress pipeline.
- List of all products transported using rural low stress pipeline.
- Pipeline location by state
- Total number of low stress pipeline miles within ½ mile of an USA
- Total number of breakout tanks associated with the low stress pipeline miles.

The survey data is to be used to assess the compliance costs associated with rulemakings promulgated under Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES Act).

Summary of Compliance Costs Survey Results

The table below summarizes the range of responses received with respect to the cost of compliance with subsections of Part 195. Of the nine targeted firms, eight provided cost data on a per mile basis for two categories: 1) As Installed and 2) To Comply. For the "As Installed" category, respondents provided estimates on the costs of installed hardware and existing programs that overlap with Part 195 requirements. For the "To Comply" category, respondents provided estimates on the per mile costs that would be incurred to reach full compliance on their unregulated pipeline inventory. A mean was calculated for each requirement to serve as a point of reference. Note that in some requirement areas, specifically the pipeline markers and integrity management program, the high and low ranges vary considerably due to one firm's assertion that their existing programs include elements beyond the proposed requirements.

Exhibit 3-3: Range of Compliance Costs per Pipeline Mile from Survey Results (Dollars)

	MarkWest	Plains All American Pipeline	Marathon	ConocoPhillips
Markers	300	125	NA	2,000
Public Education	500	25	113	73
Damage Prevention	600	33	887	50
Cathodic Protection	800	10,000	1,132	6,400
Integrity Management Program	1,000	29,000	18,000	NA
Total	3,200	39,183	20,132	8,523

**Respondent noted that the company's installed pipeline marker program includes components that may go beyond Part 195 requirements.*
*** Volpe Center received only one response to this survey question. No true high, low or median can be provided or calculated.*

3.3 Independent Engineering Estimates of Compliance Costs

As part of this regulatory impact evaluation, an independent engineering assessment was performed to estimate the compliance costs faced by affected pipeline operators. The engineers identified key technologies and procedures that affected operators will need to implement to comply with the proposed rule. Estimated costs, summarized by statutory section in the sections below, were compiled from trade catalogs, vendor price lists, and quotes from providers of specific services and hardware.

Phase II Compliance Methods & Unit Costs

The Secretary of Transportation is required to adopt minimum pipeline safety standards for rural, low stress, hazardous liquid pipelines in accordance with the PIPES Act of 2006, as codified by 49 USC 60102(k). The adopted regulations shall be to the "same standards and regulations as other hazardous liquid pipelines." The implementation of the applicable standards and regulatory requirements may be phased in, and PHMSA has elected to proceed with a phased approach. In Phase I of the rulemaking, PHMSA incorporated rural low stress steel or plastic pipelines having a nominal diameter equal or greater than 8 ⅝ inches whose failure could affect an USA into 49 CFR 195 regulations and adopted reporting requirements for all rural, low stress hazardous liquid pipelines. For Phase II, PHMSA is considering regulation of rural, low stress, hazardous liquid pipelines, not previously regulated by 49 CFR 195 except for reporting, for the following categories:

- Low stress pipelines having a nominal diameter less than 8 ⅝ inches with maximum operating pressure ≤ 20 percent Specified Yield Minimum Stress (SYMS), or ≤125 psig for steel pipelines if the stress level is unknown or plastic pipelines whose failure could affect an USA

- Low stress pipelines having a nominal diameter 8⅝ inches or greater with maximum operating pressure ≤ 20 percent SYMS, or ≤ 125 psig for steel pipelines if the stress level is unknown or plastic pipelines

PHMSA estimates that 1,263 miles of rural low stress hazardous liquids pipelines will be subject to Phase II rulemaking. Of that, approximately 161 miles may potentially impact an USA. Such pipelines will be economically impacted by the proposed rule. Cost impact dependencies and outcomes include:

- Operator regulated status for other pipelines
- Size and financial resources of the operator
- Operator's operations and maintenance pipeline safety practices
- Pipeline characteristics and conditions
- Regional and site conditions
- Existing State statutes and regulations in absence of PHMSA regulations (e.g., State One-Call laws, intrastate pipeline regulation)
- Personnel regulatory status (OQ, Drug and Alcohol)

Several pipeline operators are relatively short laterals per review of the Volpe Center survey data. Thus, operator fixed costs tend to be a more important factor than cost-per-pipeline mile economic analyses. However, crude oil pipeline operators may have longer lines. Further analysis may be appropriate according upstream, midstream and downstream pipeline sectors.

Much of Part 195 regulatory requirements reflect standards and practices already in place for many pipeline segments. Practices in the pipeline industry are often the result of consequences from spills and accidents. For each regulatory requirement there is the total cost of meeting that requirement and incremental cost of meeting the requirement. For example, for cathodic protection there is a total cost to provide cathodic protection to a pipeline segment. However many pipeline companies would have cathodic protection in the absence of regulation. The cost of the regulation therefore is the incremental cost of moving from current industry state to full regulatory compliance.

This section does not address the potential cost impacts due to:

- Additional requirements of State pipeline laws and regulations
- Future PHMSA rulemakings (e.g. pipeline control management) on affected operators
- Hazardous pipeline classification, civil, and criminal penalties as may be provided for in Part 190.

Most hazardous liquid pipelines are constructed with steel pipe and are operated at a pressure creating a hoop stress in excess of 20 percent of SMYS because it is not economical to construct and operate pipelines to operate at low pressures to transport significant volumes of product over long distances. Some pipelines are operated at 20 percent or less of SMYS for varying reasons because they are:

- Shorter laterals or delivery lines
- Dedicated petroleum product blendstock or petrochemical lines
- Not required to operate at high pressures
- Old and in poor condition
- Operated at lower pressures due to market conditions or reduced volume throughput

The independent engineering assessment of compliance costs were developed from Volpe Center data and interviews with industry contacts. Exhibit 3-4 provides the independent engineering assessment of the incremental cost to comply with each subpart of the Phase II regulation. The following paragraphs address potential costs arranged by statutory and regulatory sections. The cost data was provided to PHMSA by an independent pipeline engineering consultant.

Exhibit 3-4: Independent Engineering Compliance Costs by Statutory Section & Method

SECTION & METHOD	LOW	HIGH	UNIT OF MEASURE
§195.1 -- Operator Recognition, Understanding and Internal Communications			
Existing Pipeline Operators	Nominal	$25,000	initial one-time cost per operator
New or Small Operators	$25,000	$50,000	initial one-time cost per operator
§195.6 -- Identification of USAs			
USA Investigation (No Field Survey)	$1,000	$5,000	per pipeline segment
§195.7 -- Review of Conversion of Service			
Conversion of Service	$ -	$ -	per operator
§195.12 – Requirements for Rural, Low Stress Pipelines			
Subpart A			
Stress Level Field Investigation			
Excavations	$60,000	$100,000	per pipeline mile
ROW Damages	$5,000	$50,000	per pipeline mile
Subpart B - Reporting			
Annual Reporting	$ -	$4,000	per year
Subpart C – Design			
Valve Site (Mechanical Only)	$2,500		per occurrence
Launcher / Receiver Site	$7,500		per occurrence
CPM Leak Detection	$ -	$ -	
Subpart D - Construction			
CONSTRUCTION – General	Unknown	Unknown	Site specific costs unknown
Subpart E - Pressure Testing			
Pressure Testing	$75,000	$100,000	per existing pipeline
Subpart F - Operation & Maintenance			
Operations, Maintenance and Emergency Manual	$15,000	$20,000	per operator with no existing manual
Required Emergency Equipment			
Air Purifying Respirator			per item
Half-Mask w/ box of cartridges	$125		per item
Full-Face w/ box of cartridges	$325		per item
Welding Full Face w/ box of cartridges	$525		per item
Self-Contained Breathing Apparatus (SCBA)	$2,500	$3,200	per item
Emergency Harness and Line	$400		per item
Spill Response Trailer and Emergency Supplies	$20,000	$50,000	per operator with no existing contract
Emergency Training		$10,000	per operator with no existing program
Mapping Activities			
Aerial Survey (used for longer 20+ mile pipelines)	$17,000		per pipeline
Field Survey	$ 5,000	$20,000	per pipeline
Engineering Mapping after Survey	$ 1,200		per pipeline mile (minimum $5,000)
Breakout Tank Facility (Mechanical Only)	$10,000	$15,000	per facility
Breakout Tank or Pump Station Facility (Electrical – Depending facility size and operator's scope)	$5,000	$40,000	per tank or pump station facility
Facility Breakout Spill Containment Analysis	$2,000	$10,000	per facility
Maximum Operating Pressure Determination	$1,000	$10,000	per pipeline segment
Fixed Communications	$50,000		per pipeline segment
Marker Type Installation			per pipeline mile
Line Markers	$1,000	$ 1,200	
Aerial Markers	$100	$450	per pipeline mile
Aerial Patrol Service	$33	$43	per mile annually for bi-weekly service
ROW Clearing by Vegetal Type			
Forested (Wooded – up to 4"-6" diameter trunks)	$2,800		per pipeline mile annually

SECTION & METHOD	LOW	HIGH	UNIT OF MEASURE
Wetland Clearing (Hand Clearing)	$2,250		per pipeline mile annually
Heavy Brush	$1,600		per pipeline mile annually
Mowing (includes trimming low canopy)	$1,500		per pipeline mile annually
Mowing and Canopy Clearing (up to 75-ft height at specified locations)	$1,785		per pipeline mile annually
Annual In-Service Breakout Tank Inspection	$5,000	$10,000	per site
Public Awareness Plan	$10,000	$15,000	Annually
Public Outreach	$2,200	$9,500	Annually
Effectiveness Evaluation	$2,500		
Utility One-Call Membership and Participation	Nominal		Annually
Contract Locate Service	$500		per locate (estimated for 2 to 3 per year)
Written Integrity Management Framework Program	$15,000	$25,000	dependent on existing framework acceptability
Risk Assessment and Prioritize	$-	$50,000	dependent on existing framework acceptability
Pressure Testing	$ 75,000	$100,000	per pipeline
Integrity Assessment Costs			
ILI Assessment Method			
Pipeline Modification and Preparation			
Launcher / Receiver Installation	$150,000		per pipeline segment
Confirmation Excavations [1]	$10,000	$15,000	per site if needed
Gauging and Cleaning Pig	$3,200		
Records Review and AGM Setup	$5,000	$1,000	per operator
Action Plan, Specifications, Vendor Selection	$15,000		per operator
Caliper Tool Run	$12,000		per occurrence
High Resolution MFL (Corrosion) Tool	$21,000		per occurrence
Contractor Field Support	$ 5,000	$10,000	per occurrence
Excavations and Repair	$15,000	$20,000	per occurrence
Post-Assessment Analysis and Reporting	$5,000	$10,000	per occurrence
Pre-Assessment Phase	$5,000	$10,000	
Indirect Inspection [1]	$2,500	$18,000	per pipeline mile
Direct Examination (Excavations)	$15,000	$20,000	per excavation (1 to 3 excavations per mile)
Post-Assessment and Reevaluation	$5,000	$10,000	per occurrence
GWUT	$15,000	$20,000	per occurrence
Subpart G - Qualifications of Pipeline Personnel			
Operator Plan Preparation	$10,000	$15,000	
Operator Service On-Line Recordkeeping	$3,000		initial cost
Personnel Qualification	$1,000	$5,000	initial cost
Personnel Recordkeeping	$2,000		(per 20 individuals)
Exposed Pipe Inspection	$5,000		per year
Cathodic Protection Records Review	$5,000	$10,000	
CIS Field Survey	$500	$ 900	per pipeline mile
Annual Test Station Survey	$3,000	$5,000	per year
Subpart H - Corrosion Control			
Cathodic Protection Mainline	$5,000	$50,000	per pipeline mile
Tank Bottom Cathodic Protection Installation	$15,000	$30,000	per tank
Cathodic Protection Records Review	$5,000	$10,000	
CIS Field Survey	$500	$900	per pipeline mile
Annual Test Station Survey	$ 3,000	$5,000	per pipeline segment
Data Gathering	$4,000	$5,000	per pipeline mile
Design	$50,000	$125,000	per 10 to 20 mile segment
Installation	$250,000	$300,000	per 10 to 20 mile segment
Initial Study and Recommendations	$10,000		per pipeline
Field Sampling and Investigation	$10,000	$15,000	per pipeline
API Out-of-Service Breakout Tank Inspection	$6,000	$12,000	per tank
Tank Floor Coating	$30,000		per tank
Installation of Corrosion Coupons or Other Monitoring	$5,000	$7,500	per installation as needed

SECTION & METHOD	LOW	HIGH	UNIT OF MEASURE
Equipment			
Annual Monitoring Program	$5,000	$10,000	per year
New Operator D&A Plan	$800		per operator
Initial Employee Registration	$20,000		per 20 employees
Additional Employees	$150		per additional employee
Drug Program Administration	Nominal	Nominal	per operator

Note that affected operators may select from a range of compliance measures to match their current pipeline configuration and existing practices. The cost estimates do not differentiate the cost impacts by Phase II requirements and the use of consensus standards and internal policies already in place by operators. Therefore, compliance costs may vary significantly from operator to operator whether large or small.

TITLE 49 USC 60301

Section 60301 of Title 49 of the United States Code authorizes the Department of Transportation to assess and collect user fees from the pipeline industry to fund the Department's pipeline safety program. Fees are based on usage of the pipelines (in reasonable relationship to volume-miles, miles, revenues, or a combination of volume-miles, miles, and revenues). A fee collected related to a hazardous liquid pipeline facility may be used only for an activity related to a hazardous liquid under Chapter 601 of Title 49. For the FY 2009 user fee cycle, PHMSA is billing hazardous liquid operators at $111.92 per mile.

49 CFR PART 195

49 CFR Part 195 is divided in to several subparts. The following sections provide a breakdown of the costs by subpart.

SUBPART A - GENERAL

Potential cost impacts include:

- Operator Recognition, Understanding, and Internal Communications
- Identification of Rural Low Stress Pipeline Segments or Systems
- Identification of USAs
- Review of Conversion of Service
- Non-Steel Pipeline Hazardous Liquid Transportation

§195.1 - Operator Recognition, Understanding and Internal Communications

The direct cost for operator recognition, understanding and internal communication depends on operator size, experience, geographical location of newly regulated facilities, and the number of employees and contractors affected by the rule.

Due to the limited mileage, it is believed that existing large pipeline operators have adequate personnel resources to handle the additional assignments that may be required. Small pipeline operators or non-traditional operators (e.g., petroleum refiners, chemical manufacturing, bulk marketing terminals), or other operators not previously regulated by Part 195 may have resource shortfalls.

There should be less impact for operators already regulated under Part 195, although there may be increased compliance cost for pipeline facilities widely separated geographically or not part of operator's regulatory pipeline organization (e.g., a bulk marketing terminal with a delivery pipeline or a pipeline operated by a separate division).

For a newly regulated operator, it is estimated to take six months for preparation, set-up and implementation of internal communication systems. There may also be additional time and cost necessary consultants and contractors to assist the operator.

Exhibit 3-5: Phase II Compliance Cost

Phase II Compliance	**Cost**
Existing Pipeline Operators	Nominal - $2,500 per operator
New or Small Operators	$25,000 - $50,000 (initial)

If the operator believes that the Phase II rule is economically burdensome, the operator has the option to petition PHMSA for relief. The operator economic burden is determined to be approximately $5,000 to $20,000 per pipeline segment.

§195.6 - Identification of USAs

It is important for pipeline operators with small diameter low stress pipeline segments to determine whether they are subject to other parts of Part 195 besides Subpart B reporting. In many cases, operators should have determined USA impacts as part of annual reporting requirements of the Phase I rulemaking.

An USA is a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release, as identified under 49 CFR §195.6. As part of the National Pipeline Mapping System (NPMS) in 2000, the Office of Pipeline Safety obtained and mapped the data for use by governmental officials and operators. Registered operators can obtain the digital mapping datasets for analysis and incorporate into integrity management plans. To minimize the potential cost for an operator, the data is compatible with "GIS-lite" map viewers. Alternatively, operators may opt to purchase geographical information system (GIS) software.

However, the USA mapping information that an operator uses may not be current, and additional cost could be incurred for additional investigation. For drinking water USAs, an operator can use a United States Environmental Protection Agency's (US EPA's) databases or contact the US EPA or State water resource offices. For ecological USAs, an operator can contact State National Heritage Program and United States Fish and Wildlife (USFWS) regional ecological offices and use Naturserv and NOAA's Office of Response and Restoration mapping data. Information may be available in various formats. Operators may need to acquire software or hire outside consultants to use such data. In certain circumstances, site surveys for candidate species by qualified individuals may be required. Such surveys may be limited by property owner permission for right-of-entry. Although USAs are not expected to change, the operator will need to periodically determine whether new USAs may be impacted by a pipeline segment and then take appropriate regulatory compliance action. The cost of an USA investigation is estimated to be $1,000 to $5,000 per pipeline segment.

§195.5 - Review of Conversion of Service

This section of the regulation applies only to pipeline systems being converted to hazardous liquid service from another service. It does not apply to pipeline systems that are potentially subject to regulation. Therefore, there is no cost impact due to this section.

§195.8 - Non-Steel Pipeline Hazardous Liquid Transportation

Provisions are provided under 49 CFR §195.8 to notify PHMSA of hazardous liquid pipeline transportation through non-steel pipe. It is not known whether non-steel pipelines exist that will become subject to 49 CFR 195, although the mileage of non-steel pipelines is believed to be limited. The operator is only obligated to provide written notification to PHMSA (or a state-certified agency, as applicable) 90 days before transportation is to begin. Then PHMSA must act upon the notice action within 90 days and make a determination.

The potential costs that may be incurred by the operator to obtain approvals or special permits from PHMSA are not known. If approvals or special permits cannot be obtained in a timely manner, the operator may be obliged to sell, idle, or abandon the pipeline.

There is no recent precedent on what PHMSA could require from an operator. But, unless an operator is using a higher pressure-rated fiberglass or other specialized plastic pipe, it is not believed that the rule limitation of 125-psig will have cost impacts. If an affected pipeline is operating above 125 psig, the operator will incur additional cost to petition PHMSA for a special permit in accordance with 49 CFR §190.341. Alternatively, the pipeline operator could attempt to demonstrate to PHMSA that the reduced pressure will impose an economic burden in accordance with 49 CFR §195.12(c).

Given the lack of non-steel pipelines and industry precedents, no cost information was developed.

Breakout Tanks

Certain facilities, subject to the rulemaking, may have tanks that would be determined as breakout tanks. Such tankage and associated areas may be regulated by state or local fire codes, State Aboveground Tank (AST) regulations, and US EPA Spill Prevention, Containment, and Countermeasure (SPCC) regulations. Furthermore, such tankage could require revisions of Facility Response Plans (FRPs) in accordance with the Oil Pollution Act of 1990 and other state response plans. Operators may need to notify potentially affected agencies of the reclassification of the affected tanks, modify applicable plans, and seek approvals of such modified plans from all affected agencies. Applicable affected agencies may lose revenue without corresponding benefit due to the jurisdictional reassignment. The number of such potentially affected facilities is not known. The type and use of breakout tanks (e.g., roll-off tanks) for temporary pipeline maintenance and replacement activities may need to be changed since they may not meet the listed tank types.

§ 195.12 - Requirements for Rural Low Stress Pipelines

The potential immediate cost impacts are determining applicability and stress level. Since applicability has been addressed elsewhere, only the unknown stress level and potential pressure reduction and reduced throughput are addressed here. For purposes of discussion, PHMSA accepts at face value that a pipeline can be considered as low stress based upon operators MOP, operating pressure and assumed pipe parameters. If records are not available to establish stress level, the operator may be obligated to excavate and expose the pipe to measure wall thickness or reduce maximum operating pressure to less than 100 psig. The pressure reduction could result in lower throughput and revenue. For determining stress level, the operator needs to know a pipelines SYMS and pipe wall thickness.

If the SYMS is not known, the operator must take pipe samples and test the samples in accordance with the §195.106 requirements. If that is not practical, the yield strength is taken at 24,000 psig. Pipe wall thickness is determined in accordance with §195.106 for 10 individual lengths or 5 percent of all lengths, whichever is greater. For assumed double-random joints (40 ft ± lengths), 10 excavations per mile may be required. Cost are estimated to be $6,000 to $10,000 per excavation at depths less than 6 feet. Estimated right-of way (ROW) damages may range from $500 to $5,000 per excavation for agricultural lands.

SUBPART B - Reporting Requirements

This Subpart prescribes requirements for periodic reporting and for reporting of accidents and safety-related conditions. For annual reporting, nominal cost impact is anticipated due to Phase II rulemaking due to expected limited pipeline mileage for each operator. Annual report costs are estimated to cost up to $4,000.

SUBPART C - Design Requirements

This Subpart prescribes the minimum design requirements for new pipeline systems constructed with steel pipe and for relocating, replacing, or otherwise changing existing systems constructed with steel pipe. This section closely conforms to the ASME B31.4 consensus standard. For certain circumstances, Subpart C requires additional analysis for anticipated external loads (e.g., earthquakes).

Initially, there could be cost for pipe, bends, bar-tees, installation and right-of-way for replacement sections to accommodate the passage of instrumented, internal inspection (ILI) devices for mainline sections for those pipeline segments affecting an USA and ILI tools are used as an assessment method. Later, the operator may install additional new valves to provide increased USA protection.

There may be limited instances for some newly regulated breakout tanks that were placed in service after October 2, 2002, which may not conform to 49 CFR §195.132. The operator will need to obtain a special permit in accordance with 49 CFR §190.341 at an unspecified cost. The potential site specific costs for replacement at a value site (mechanical only) is estimated to be $2,500 per occurrence. The potential site specific costs for replacement at a launcher / receiver site is estimated to be $7,500 per occurrence.

§195.134 - CPM Leak Detection

Each replaced component of an existing computational pipeline monitoring (CPM) system must comply with section 4.2 of API 1130 in its design and with any other design criteria addressed in API 1130 for components of the CPM leak detection system. In the NPRM process for CPMs, the USDOT Research and Special Programs Administration (RSPA) solicited cost information from the regulated pipeline industry in the 1990s, and no responses were received. RSPA concluded as part of final rulemaking that the cost for this regulation was believed to be minimal.

Since the adoption of the rule, it is not known whether non-API 1130 CPM leak detection systems still exist due to equipment obsolescence and technology improvements based upon discussion with a CPM vendor. The immediate and future cost effect is expected to be minimal.

SUBPART D - CONSTRUCTION

This Subpart prescribes minimum requirements for constructing new pipeline systems with steel pipe, and for relocating, replacing, or otherwise changing existing pipeline systems that are constructed with steel pipe. There may be other cost impacts due to other sections and operator decision making (e.g., additional valves to protect USAs). It is assumed that this section applies to such work after the rule goes into effect. There may be unregulated breakout tanks that were constructed after specific dates cited for construction. Such modifications may be cost significant. Operators may need to request a special permit under 49 CFR § 190.341 or show PHMSA that the regulation will impose an economic burden in accordance with 49 CFR § 195.12(c). An operator may need to change documentation and recordkeeping practices for pipeline construction to comply with this section. Operators may need to change practices and use of tanks for pipeline replacement and maintenance purposes because they are not listed.

SUBPART E - PRESSURE TESTING

Unless otherwise provided in § 195.302 and § 195.305(b), the operator will be obligated to show that the affected pipeline segment has been tested in accordance with this Subpart or incur the cost to perform pressure testing. For affected pipeline segments potentially affecting USAs, such tests may be also be used as a baseline and recurring assessment as part of the integrity management program for steel pipelines less than 8⅝ inches nominal diameter.

For pipeline segments believed to be subject to the rule, the cost is estimated to be in the range of $75,000 to $100,000. The cost is fairly insensitive to the pipeline mileage due to the relatively short segments believed subject to the proposed rule. Water is normally used as the test medium due to risk management considerations. Nitrogen displacement and pigging operations are used to minimize product contamination and waste. This operation assumes that the operator has water-handling or treatment facilities for petroleum-contaminated water. There may be other operator costs including lost revenue for pipeline downtime, logistical planning, and scheduling.

SUBPART F - OPERATION AND MAINTENANCE

This Subpart prescribes minimum requirements for operating and maintaining pipeline systems constructed with steel pipe. There will likely be cost impacts for compliance.

§195.402 - Procedural Manual for Operations, Maintenance, and Emergencies

Each operator must prepare and implement for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. The cost impact will depend on whether an operator already has a manual for regulated pipeline systems and whether specific practices may already be implemented. Preparation of a manual is estimated to cost $15,000 to $20,000. Such cost is independent of pipeline mileage. Ongoing costs attributed to personnel training and review of the manual for adequacy is expected to be nominal.

Abandoning Pipeline Facilities

The potential need to abandon depends upon the economic usefulness of a pipeline segment. Such an operator decision may occur due to the potential regulatory compliance cost, age and condition of the pipeline, operating and maintenance history, potential replacement cost, revenue benefit, future usefulness, and market conditions for potential resale. The immediate cost impact of pipeline facility abandonment has not yet been determined.

Abandonment may incur cost for landowner notifications, property damage settlements and restoration, product removal, pipe handling and disposal, permits or approvals for earth and sediment disturbances from the US Army Corps of Engineers or other State water quality agencies. For some sections, it may be impractical to remove the pipe. Pipe may be filled with grout. Subject to State law and the terms and conditions of right-of way easements and licenses, the operator could lose the rights.

Current practice by some operators is to remove the pipeline out of active service and "idle" the line to retain legal rights. PHMSA does not recognize "idling" and expects the operator to maintain the pipeline in accordance with 49 CFR Part 195. However, if a pipeline is idled properly, PHMSA considers the pipeline as a low environmental risk.

Minimizing Hazard of Accidental Ignition

No cost impact is expected with activities associated with minimizing hazard of accidental ignition.

Establishing Liaison with Emergency Responders

Minimal cost impact is expected. Some elements are incorporated with the public awareness program and with other federal, state and local public awareness and emergency management programs. Also, certain facilities may be subject to Superfund Amendments and Reauthorization Act (SARA) Title III Right-to-Know rules. Title III establishes requirements for federal, state, and local governments and industry regarding emergency planning and "Community Right-to-Know" (CRTK) reporting on hazardous and toxic chemicals. States and communities, working with facilities, will be better able to improve chemical safety, protect public health, and safeguard the environment.

Periodic Personnel Reviews

No significant cost impact for periodic personnel reviews is anticipated.

Appropriate Precautions in Excavated Trenches including Emergency Equipment

Operators may incur cost for the purchase and maintenance of safety breathing apparatus and rescue harness and line equipment. For unregulated operators, there is the potential liability concern of providing such equipment for contract personnel due to OSHA's requirements although PHMSA's requirements supersede. Exhibit 3-6 provides typical, estimated pricing for different respirator types and emergency harness and line as compiled from standard industry catalogues for safety equipment. This type of equipment is used both for regular pipeline operations and also for additional activities required by regulation.

Exhibit 3-6: Cost of Safety and Emergency Equipment

Required Emergency Equipment	Estimated Price Per Unit
Air Purifying Respirator	
Half-Mask w/ box of cartridges	$125
Full-Face w/ box of cartridges	$325
Welding Full Face w/ box of cartridges	$525
Self-Contained Breathing Apparatus (SCBA)	$2,500 - $3200
Emergency Harness and Line	$400

Typically, an operator will store such equipment at a regional location for use as needed. Additional nominal costs for operator procurement, training, maintenance, and testing of the equipment for a state of readiness will be incurred.

Emergency Equipment and Supplies

Operators may need to procure spill response equipment trailer and supplies for emergencies and have on-call contracts for contractors and material for emergencies, if not already provided. Spill response trailer and emergency supplies are estimated to cost between $20,000 and $50,000. Operators may have Oil

Spill Removal Organizations (OSRO) contractors, equipment and supplies and be covered under Part 194 OPA 90 and other state response plans.

§ 195.403 - Emergency Response Training

Pipeline operators are required to conduct emergency response training which includes personnel training, emergency response drills and table top exercises. A review at least once a year regarding personnel performance and adequacy of the training program is expected. It is believed that such operators with pipeline segments are subject to preparing OPA 90 oil response plans under Part 194 and also subject to state oil spill response plans. In addition, the public awareness program also fulfills certain hazard communications to emergency responders. Emergency training is estimated to cost approximately $10,000 annually. Operators may be covered under Part 194 and other state response plans in performing such training.

§ 195.404 - Maps and Records

Maps and records availability may be problematic for pipeline facilities not previously regulated. Quality and availability of maps and records are subject to age of the pipeline facilities, operator recognition, documentation, recordkeeping, management of change, transfer process of records to new operators, and casualty loss. Operators for unregulated facilities may have different record retention practices than 49 CFR 195. Although generally recognized engineering and construction practices may have been used, documentation and records retention may not have deemed as important due to operator practices, additional cost, schedule, and work force limitations.

Other documentation cost could include verification of pipe and equipment, and components for pump stations, breakout tank areas, and mainline pipeline segments. Additional costs may be incurred for other engineering drawings including process and instrumentation diagrams, process flow diagrams, and electrical drawings. Exhibit 3-7 provides map and record keeping costs. These data were developed from internal cost records for actual bids and estimates submitted and developed by pipeline contractors.

Exhibit 3-7: Potential Map and Record Keeping Costs

Activity	Cost
Aerial Survey*	$17,000
Field Survey*	$5,000 -- $20,000
Engineering Mapping after Survey	$1,200 per mile ($5,000 min.)
Breakout Tank Facility (Mechanical Only)	$10,000 - $15,000
Breakout Tank or Pump Station Facility (Electrical - Depending facility size and operator's scope)	$5,000 -- $40,000
Facility Breakout Spill Containment Analysis	$2,000 -- $10,000

* *Upper limit cost based upon 20-mile length pipeline. Aerial surveys would tend to be used for longer pipelines.*

An alternative to field or aerial surveys is an ILI geographic mapping tool for pipelines. Cost for such services may range from $50,000 to $100,000 for a dedicated run. Some of this cost can be reduced if the tool is run with a MFL tool.

§ 195.405 - Protection against Ignitions and Safe Access/Egress with Floating Roof Tanks

Minimal cost impact is expected. Industry has API written standards and practices, and the tanks and related activities may be regulated by State and local fire codes, and Federal and State OSHA safety regulations. NFPA 30 consensus standard specifies that precautions be taken to prevent the ignition of flammable vapors from several sources, prevention from hazards of static electricity, the requirement for a "hot-work" permit, the requirements for design, selection and installation of electrical wiring and electrical utilization equipment. API Standard 2003 addresses static electricity and stray currents control relevant to the prevention of hydrocarbon ignition in the petroleum industry. API Publication 2026 addresses the hazards associated with access/egress onto external and internal floating roofs of in-service petroleum storage tanks and identifies some of the most common practices and procedures for safely accomplishing this activity.

§ 195.406 - Maximum Operating Pressure

Potential cost to determine the maximum operating pressure (MOP) for a pipeline segment includes review of records or in absence of such information, operations and site investigation and tests for:

- Internal design pressure of the pipe in accordance with § 195.106
- Design pressure of other components of the pipeline
- Pressure tests in accordance with Subpart E
- Factory pressure or prototype test pressure for individually installed components
- Other test pressure or highest operating pressure to which the pipeline has been subjected for four continuous hours

The cost and time to establish the MOP for compliance purposes depends upon quality of records and due diligence research. A pressure test to establish the MOP may be performed in conjunction with a baseline assessment. Maximum operating pressure determinations are estimated to cost between $1,000 and $100,000. For example an inexpensive low end pressure determination would be accomplished by looking at previous records or by a simple pressure test. The cost depends on how the operator determines the MOP.

§195.408 - Communications

A fixed communication system to transmit operational data including a SCADA system could be a significant capital cost item depending upon sophistication. Dedicated telephone lines, satellite dish, line-of-sight transmission, or cellular dial-up services may be utilized. Cost will be increased if CPM leak detection is installed as a best practice for USA protection. It is assumed that pipeline "control room" is manned and pipeline operations are being monitored during shipping or receipt operations. Other provisions have minimal costs and necessary equipment should be in place, such as walkie talkies, telephone, cell phones, operator logs, and training. Fixed communication costs are estimated to be at least $50,000 per pipeline segment.

§ 195.410 - Line Marker Cost Installation

Operators are obligated to place and maintain line markers over each buried pipeline at each public road crossing, at each railroad crossing, in sufficient number along the remainder of each buried line so that its location is accurately known, and at locations where the line is aboveground in areas that are accessible to the public. ASME B31.4 consensus standard provides similar guidance, references the use of aerial markers and instructs that API RP 1109 should be used for guidance. PHMSA and the pipeline industry recognize the limits for the rule application due to operator's right-of-way rights and land use. Installing markers at "line-of-sight" intervals to accurately locate the pipeline is not practical, especially in agricultural areas. API plans to revise API RP 1109 to reflect various realities and Common Ground

Alliance guidelines. Based upon present pipeline operator practice, newly regulated pipelines will be likely marked consistent with present practice.

In the Phase I rulemaking, an estimate of 10 line markers per mile was used based upon the Independent Petroleum Association of America's (IPAA) estimate for gas gathering lines. Based upon observations in the rural Midwest, 5-6 line markers per mile is more representative. Estimated contractor-installed cost is $200 per marker including locating the line. Since rural pipelines will likely be aerial patrolled, aerial markers will be installed approximately at 4-mile intervals. Estimated contractor installed cost is $450 per marker (5 markers minimum due to vendor order minimum). Marker type installation costs per mile are estimated to be $1,000 to $1,200 for line markers and $100 to $450 for aerial markers.

§ 195.412 - Inspection of Rights-of-Way

Two elements are required for suitable inspection of the right-of-way:

- Recurring patrols
- Maintenance of the Right-of-Way

Each operator must, at intervals not exceeding three weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Some operators may elect to perform this task more frequently for risk management and integrity management purposes. This task includes performing right-of-way or easement patrol (e.g., walking, driving, or flying) to visually identify signs of leaks, encroachments, conditions of the right-of-way, or other signs that could impact pipeline safety or integrity and reporting. Such inspections may also occur for emergency incidents.

For rural pipeline segments potentially impacting an USA, the operator may increase the frequency of patrols to every week as an integrity management best practice. The cost will correspondingly increase. Inspections will likely be by aerial surveillance unless accessibility and short length of the pipeline segment can make other means practical. Aerial patrols may be performed by fixed-wing aircraft or helicopters. Estimated average recurring cost for contract aerial patrol is $1.30 - $1.65 per mile with a $100 minimum charge. Cost is dependent upon regional differences and if the patrol must be deadheaded or can be combined with other pipelines in an area. In addition, operators will need to have personnel dedicated to monitor the pilot's reports and be able to respond to an unknown encroachment activity in a timely manner. If operators do not have the available qualified personnel, additional employee(s) or contract personnel will be required.

The ability for pilots to monitor third-party activities and visibly detect potential leaks in proximity of the pipeline is subject to right-of-way condition and Federal Aviation Administration (FAA) airspace restrictions. The annual cost for biweekly aerial patrol service is estimated to be $32.80 to $42.60 per mile, with a minimum annual cost of $2,600. For a successful right-of-way maintenance program for patrolling purposes, the operator needs to understand and integrate property rights law, and environmental, regulatory, and social matters. The cost, ability and timing to clear the right-of-way are dependent upon several factors including:

- State Laws and Local and Ordinances
- Landowner Acceptance and Public Affairs
- Impacts to Environmental Sensitive Areas
- USDA and State Agriculture Departments Restrictions
- Type and Extent of Vegetation
- Climate

- Terrain
- Contractor Availability
- ROW Management Budget

The legal right with the landowner to clear and maintain the right-of-way generally resides in the terms and conditions in the pipeline easement, license or permit agreement. Such agreements may be with private individuals, companies, Federal or State land management agencies (e.g., USFS, USFWS, BLM, State or Regional Parks), or road agencies. For cultivated, agricultural lands, operators allow the landowners to produce crops.

Vegetation management can be a challenge due to the diversity of landowners and interests. Considerable time can be expended to identify landowner by review of land ownership records and then notify the landowners or lease holders prior to clearing. Landowners may have aesthetic, environmental and commercial concerns that may require considerable time and expense to resolve. ROW clearing may be restricted or cost more in wetlands and other environmentally sensitive areas. Exhibit 3-8 provides representative cost estimates for ROW clearing where there are no impediments, such as buildings, steep grades, etc. This data was collected from a phone survey of ROW clearing contractors.

Exhibit 3-8: ROW Clearing Costs

Vegetation Type	Cost, $/mi
Forested (Wooded – up to 4"-6" diameter trunks)	$2,800
Wetland Clearing (Hand Clearing)	$2,250
Heavy Brush	$1,600
Mowing (includes trimming low canopy)	$1,500
Mowing and Canopy Clearing (up to 75-ft height at specified locations)	$1,785

The cost estimates include a 1.25 multiplier factor for steep terrain, forested areas, and areas not accessible by vehicles. In general, operators clear trees and shrubs within 25 feet of the pipeline for patrolling, potential maintenance and pipe protection from large roots. Mowing frequency is dependent upon the region and land use. Mowing frequency can be minimal in arid and cultivated areas. Tree canopy trimming may occur on a six-year cycle.

§ 195.420 - Valve Maintenance

There could be an increased recurring cost for inspection and maintenance to ensure that mainline valves are in good working order. Valve inspection and maintenance cost is dependent on whether the valve is manually-operated or remotely-controlled. Although time period to have the valve returned to good working order is not specified, PHMSA expects operators to make such repairs in a timely manner and before the next regularly scheduled inspection, unless the operator can demonstrate otherwise that continued operation does not compromise pipeline safety. The American Society of Mechanical Engineers (ASME) B31.4 consensus standard only specifies one inspection per year. This section specifies inspections two times per year. Operator experience and best practice for protection of USAs may dictate more frequent inspections. Valve inspection costs are expected to be nominal.

§ 195.422 - Pipeline Repairs

Possible costs could result from the need for pipe, valves or fittings that conform to Part 195 requirements. This includes alternations to pipeline segments to make them suitable for in-line inspection (ILI) tools.

§ 195.426 - Scraper and Sphere Facilities

An operator cost will be incurred when the inspection will be required of all existing scraper and sphere facilities for compliance with this section, specifically, safety relieving provision and pressure indicators. The cost for adding a safety-relieving end-closure device to an existing scraper is estimated at $14,000. This cost is estimated from an actual bid and instillation by an engineering consultant. If an operator decides such facilities are insufficient for ILI tools for integrity management purposes, the facilities need to be modified or replaced for ILI tools. The cost for new facilities is itemized with the integrity management section.

§ 195.428 - Overpressure Safety Devices and Overfill Protection Systems

Nominal cost impact for bi-annual inspection associated with overpressure safety devices and overfill protection systems is anticipated.

§ 195.430 - Firefighting Equipment

No cost impact is anticipated. This section is generally subject to agreement with the responding fire department although PHMSA has the authority to determine adequacy.

§ 195.432 - Inspection of In-Service Tanks

Estimated annual API 653 in-service inspection of a small breakout tank facility by an API 653-certified inspector cost will likely be $5,000 to $10,000 per site.

§ 195.434 - Signs

There will be an initial nominal cost for installation of signs for pumping and breakout tank area if not already installed.

§ 195.436 - Security of Facilities

Minimal cost impact is anticipated. Such facilities may be covered by State and local codes and NFPA 30 consensus standard. The American Petroleum Institute has published guidance practices.

§ 195.438 - Smoking or Open Flames

No cost impact is expected since this is consistent with recognized, good operator practice. NFPA 30 consensus standard specifies that precautions shall be taken to prevent the ignition of flammable vapors due to open flames. Also, smoking is permitted only in designated and properly identified areas. Existing facilities may be already covered by State and local fire codes and Federal and State OSHA standards. Operators may need to review existing procedures and survey aboveground pipeline facilities and post signs as needed.

§ 195.440 - Public Awareness

Each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in API RP 1162. There will be other costs associated for website and external communications media (brochures) if the operator deems that such communication methods are deemed effective.

The preparation of a written public awareness plan is estimated at $10,000 to $15,000. Additional public awareness measures include preparation of a website with a public awareness message. Annual cost for public outreach implementation is $2,200 to $9,500 per pipeline segment. Outside public outreach cost is dependent upon number of other participating pipelines in service area. Since these are low population density areas, three to four landowners per pipeline mile are assumed.

§ 195.442 - Damage Prevention

Third party damage is recognized as the leading concern for pipeline failures. Most states already require operators of the Phase II pipelines to join a State or regional One-Call excavation notification center. Thus, any costs due to planned regulation for those Phase II pipelines are expected to be zero. In some states, hazardous liquid pipeline operators are provided the option to register their facilities with the county their pipelines pass through or with the One-Call center. The excavator is obligated to contact both entities prior to excavation. This could lead to excavator confusion and potential error due to excavator's lack of knowledge of local requirements and reliance of the One-Call system and the national 811 campaign. Based upon responses of selected State One-Call centers, the membership charges are nominal. For new operators, the cost of membership is in the range of $0 to $200. Typically, operators are charged up to $3.00 per ticket, and operators may be assessed a nominal annual fee. An operator should not expect a significant number of excavation One-Calls unless it is for a special project (e.g., highway construction). Provided below is an analysis of State One-Call laws and practices and potential regulation impact. Operators may need to obtain line locating equipment and have personnel trained and qualified to mark and locate pipelines. In lieu of an operator using its employees, an operator may hire a locate service. This service is expected to cost about $500 per locate.

Exhibit 3-9: State One Call Laws and Potential Phase II Regulatory Impact

State / Jurisdiction	One-Call Coverage	Regulation Impact
Alabama	Non-mandatory One-Call membership if operator has an equivalent one-call system. Excavator must notify One-Call and other operators not part of One-Call service. When notified, operator must locate underground facility.	Potential impact. Presently an operator can join or have its equivalent one-call system. Under proposed Alabama legislation, operators will be obligated to implement a public awareness and damage prevention program about the One-Call system or operator in-house notifications.
Alaska	Alaska Regulatory Commission regulates pipelines not otherwise preempted by Federal law. No specific regulatory requirements. No requirement for all underground operators to join One-call. Excavator must contact operators not members. Operator must mark and locate line. Keep records.	Potential impact. One-call membership and set-up. Possible increased locates and recordkeeping responsibilities.
Arizona	Non-mandatory membership to One-Call. Can join as "limited-option" and provide One-Call information. Specific requirements when excavators must notify One-Call center.	Potential impact -- Possible membership and additional cost.
Arkansas	Arkansas damage prevention law references Federal law and regulations regarding hazardous liquid pipelines.	Potential impact and cost for joining One-Call association and damage prevention compliance.
California	Mandatory membership with regional One-Call center.	Minimal expected impact.
Colorado	Required One-Call membership.	Minimal expected impact.
Connecticut	Non-mandatory membership. Primary focus is public utilities.	Possible impact if rural low stress pipelines are present in state..

State / Jurisdiction	One-Call Coverage	Regulation Impact
Delaware	Mandatory membership with One-Call association. Onsite inspection during excavation activities for facilities that could be damaged during excavation. Leakage surveys due to blasting.	Minimal expected impact.
Florida	Mandatory membership with One-Call association.	Minimal expected impact.
Georgia	Mandatory membership with One-Call association.	Minimal expected impact.
Hawaii	Mandatory membership.	Minimal expected impact.
Idaho	Required membership with a One-Call association if an association is present for a county. Complete state coverage is handled by different One-Call associations.	Minimal expected impact.
Illinois	Required One-Call membership.	Minimal expected impact.
Indiana	Required One-Call membership.	Minimal expected impact.
Iowa	Required One-Call membership.	Minimal expected impact.
Kansas	Non-mandatory membership with One-Call association.	Potential impact if rural low stress pipelines exist.
Kentucky	Non-mandatory membership with One-Call. Required for operators that serve the public.	Potential impact if rural, low stress pipelines exist.
Louisiana	Required One-Call membership.	Minimal expected impact.
Maine	Required One-Call membership for petroleum transportation.	Minimal expected impact.
Maryland	Sent e-mail to Maryland PSC for clarification. Advised that the inquiry was forwarded to appropriate person. Have not received response for couple months.	
Massachusetts	Required One-Call coverage requirement for petroleum products pipeline within city or town only.	Potential impact if rural, low stress pipelines exist.
Michigan	Required One-Call membership for crude oil and petroleum pipelines.	Minimal expected impact.
Minnesota	Required One-Call membership for petroleum pipelines.	Minimal expected impact.
Mississippi	Required One-Call membership for petroleum and hazardous liquid pipelines.	Minimal expected impact.
Missouri	Required One-Call membership.	Minimal expected impact.
Montana	Required One-Call membership.	Minimal expected impact.
Nebraska	Required One-Call membership.	Minimal expected impact.
Nevada	Required One-Call membership. Also filing with County Clerk.	Minimal expected impact.
New Hampshire	No reference to petroleum or hazardous liquid pipelines or underground facilities.	Potential impact if such facilities exist.
New Jersey	Required One-Call membership unless waiver is obtained from NJ Board of Public Utilities.	Minimal expected impact.
New Mexico	Required One-Call membership.	Minimal expected impact.
New York	Required One-Call membership.	Minimal expected impact.
North Carolina	Required recording with County Register of Deeds. Non-mandatory membership with One-Call.	Potential impact if rural, low stress pipelines exist.
North Dakota	Required One-Call membership.	Minimal expected impact.
Ohio	Required One-Call membership. May file for limited membership w/ providing less information.	Potential impact for providing additional information.
Oklahoma	Required One-Call membership for crude oil, petroleum product pipelines.	Minimal expected impact.
Oregon	Required One-Call membership.	Minimal expected impact.
Pennsylvania	Required One-Call membership. Required information to provide county and township.	Minimal expected impact.

State / Jurisdiction	One-Call Coverage	Regulation Impact
Rhode Island	Membership only required for public utilities.	Potential impact if rural low stress pipelines exist.
South Carolina	Required One-Call membership.	Minimal expected impact.
South Dakota	Required One-Call membership.	Minimal expected impact.
Tennessee	Membership optional. Otherwise must file with County Register of Deeds. After 1978, must maintain records of changes underground facilities.	Potential impact if rural low stress pipelines exist.
Texas	Required One-Call membership.	Minimal expected impact.
Utah	Required filing with County Clerk or membership with One-Call association for counties with an established association. Confirmed State-wide one-call association in place Blue Stakes.	Minimal expected impact.
Vermont	Limited to public utilities.	Possible regulatory impact if rural low stress pipelines exist.
Virginia	Required One-Call membership.	Minimal expected impact.
Washington	Required One-Call membership if underground facility exists within a one- number locator service area. Washington has state-wide coverage. Excavator must notify pipeline companies.	Minimal expected impact.
Wisconsin	Required One-Call membership.	Minimal expected impact.
Wyoming	Required One-Call membership.	Minimal expected impact.
Washington DC	Limited to public utilities.	Minimal expected impact due to scope for rural low stress pipelines scope.

§ 195.444 - CPM Leak Detection

No cost impact is expected based upon discussion with a CPM leak detection provider. CPM systems built and installed not in accordance with API 1130 probably have been replaced due to lack of functionality and equipment obsolescence with present computer-based operating systems.

§ 195.452 - Integrity Management

This section applies to operators with steel pipeline segments less than 8⅝ inches in diameter that could impact USAs. There will likely be cost impacts to operators. For example, a written integrity management framework may cost $15,000 to $25,000 and a risk assessment and prioritization study may cost $0 to $50,000. Each operator of a pipeline covered by this section must:

- Develop a written integrity management program that addresses the risks on each segment of pipeline
- Include in the program a plan to carry out baseline assessments of line pipe
- Include a framework that addresses each element of the integrity management program to continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area
- Implement the program
- Follow recognized industry practices unless this section specifies otherwise or the operator can satisfactorily demonstrate an alternative practice

The regulatory cost impact on an operator is dependent whether:

- An integrity management program or appropriate elements including assessments are in place prior to rule adoption that are acceptable to PHMSA
- Operator has other pipelines subject to the IMP program
- Sufficient staffing, expertise and resources exist to manage or absorb the integrity management duties of an affected pipeline

Assessment Program

An operator must assess the integrity of the line pipe by any of the following methods:

- ILI tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves
- Pressure test conducted in accordance with subpart E
- External corrosion direct assessment (ECDA)

Other technology that the operator demonstrates to PHMSA can provide an equivalent understanding of the condition of the line pipe and have an explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule. One or more assessment method(s) may be required to establish the line pipe integrity.

If low-frequency, electric resistance welded pipe or lap-welded pipe susceptible to longitudinal seam failure is present, the operator must be then capable of assessing seam integrity and of detecting corrosion and deformation anomalies. The time period for percentage completion of baseline assessments in order of risk ranking for an operator is assumed to be the same as allowed for interstate Phase I rural, low stress pipelines. However, if an affected pipeline segment is classified as intrastate, the operator may have to prioritize assessments according with its other intrastate pipelines in a state according to risk. Such analyses are similar for continual assessments as scheduled on a five-year interval or more often, unless an operator can petition PHMSA to show a longer interval is justified.

Assessment Method Costs

Pressure testing in accordance with Subpart E is a proven method to assess the line pipe integrity, although it is expensive due to pipeline downtime and water treatment costs. Estimated cost range is $75,000 to $100,000, not including water treatment, pipeline downtime or lost revenue. No pipe repairs, pipe replacement, or excavations are performed unless there is a test failure. If the operator would be responsible for clean-up, damages, pipe repair, or replacement of the failed section, analysis for the failure and site remediation.

The use of ILI tools is a common assessment method for hazardous liquid pipelines. Initial costs include modifying the pipeline to accommodate ILI tools and confirming passage of ILI tools, and pipeline internal cleaning. Such initial work includes installing launchers and receivers, a gauge plate tool to confirm passage of ILI tools, excavating and exposing the pipe at suspected tight or miter bends, tees, and cross-overs. ILI tools rental and analysis cost is frequently charged at minimum price before unit cost (cost per mile) is exceeded.

Exhibit 3-10: ILI Assessment Methods and Costs

ILI Assessment Method	**Cost**
Pipeline Modification and Preparation	
Launcher / Receiver Installation	$150,000 per pipeline segment
Confirmation Excavations*	$10,000 - $15,000 per site (if needed)
Gauging and Cleaning Pig	$3,200
Records Review and AGM Setup	$5,000 - $10,000
Action Plan, Specifications, Vendor Selection Caliper Tool	$15,000
Caliper Tool Run	$12,000
High Resolution MFL (Corrosion) Tool	$21,000
Contractor Field Support	$5,000 - $10,000
Excavations and Repair [1]	$15,000 - $20,000 (per occurrence)
Post-Assessment Analysis and Reporting	$5000 - $10,000

* *Nominal pipe depth and exclusive of ROW damages and no interfering site conditions*

ECDA is an integrity management assessment method intended to determine and manage the impact of external corrosion on pipelines. This assessment method is used normally when other assessment methods are not feasible or compatible with the pipeline service, or could adversely impact downstream customers and users. NACE SP0502 provides the methodology for the process.

ECDA is a four-step process consisting of pre-assessment, indirect inspection, direct examination, and post-assessment. The process integrates indirect, non-obtrusive and direct examinations with the physical characteristics, environmental factors, and operating history of a pipeline. The operator may be subject to additional cost for additional direct assessment measures attributable to including third-party intrusions (mechanical damage), foreign utility crossings, or high voltage electric transmission corridors. For an baseline ECDA assessment, the time and cost will be likely higher than subsequent assessments due to inadequate records, information gathering and research to establish regions during the preassessment phase, multiple indirect inspection methods to better characterize the pipe, additional excavations, and finally post-assessment for evaluating first three phases and determining next continual assessment, up to five years apart.

Exhibit 3-11: ILI Assessment Methods and Costs

ECDA Method	**Cost**
Pre-Assessment Phase	$5,000 -- $10,000
Indirect Inspection	$2,500 - $18,000 per mile
Direct Examination (Excavations)	$15,000 - $20,000 per occurrence (1-3 excavations per mile)
Post-Assessment and Reevaluation	$5,000 -- $10,000

Other technology methods are those methods that have not been already incorporated in Part 195. The operator must petition PHMSA or the appropriate state-certified agency for approval prior to use. One such direct assessment method is long-range guided-wave ultrasonic technology (GWUT). Such method is being used for assessment of the carrier pipe in cased crossings when other approved methods are not available or do not apply. Estimated cost range for testing is $15,000 to $20,000 per cased crossing. Depending upon the outcome of the test and site conditions, operator may need to excavate and remove a section of casing to expose the carrier pipe to investigate and remediate, cut, pull and replace the carrier pipe, or relocate the pipeline at additional cost.

Other Potential Costs

The operator will be obligated for other potential costs for analysis of preventative measures. The potential cost impact will be dependent upon the outcome of the operator's analysis. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing emergency flow reducing devices (EFRDs) on a pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders, and adopting other risk management controls. An operator must evaluate the capability of its leak detection system or methodology and modify, as necessary, to protect an USA. An operator's evaluation must, at least, consider the following factors:

- Length and size of the pipeline
- Type of product
- Pipeline proximity to an USA
- Swiftness of leak detection of systems and personnel
- Response time of nearest response personnel
- Pipeline leak and repair history and cathodic protection history
- Geotechnical hazards
- Risk assessment results

Newly Identified Areas

For rural low stress pipelines not regulated except for reporting purposes, the operator will need to periodically determine whether new USAs could be impacted by the pipeline and thus be subject to the Phase II rule. The affected segment must be incorporated within one year of the baseline assessment plan and the baseline assessment be completed within five years of the USA identification.

SUBPART G - QUALIFICATION OF PIPELINE PERSONNEL

This Subpart prescribes the minimum requirements for operator qualification (OQ) of individuals performing covered tasks on a pipeline facility. The pipeline operator will be obligated to prepare and implement a written plan for evaluating and qualifying individuals, defining covered tasks and ensuring appropriate personnel are performing appropriate operations and maintenance tasks. The program extends to contract personnel performing such work.

Operator may maintain records or use an outside service for verification of personnel qualifications. Typical costs include plan set-up, initial training and qualification of personnel, ongoing personnel verification, and requalification of individuals typically on a 3-5 year interval. Operator qualification procedures and practices may cause indirect cost impacts to contractors for training, qualification and recordkeeping if not already participating in an operator's program. Such costs may or may not be passed through as a direct cost or as an indirect cost through labor rates.

Exhibit 3-12: Operator Plan Program and Costs

Operator Plan Program	**Cost**
Operator Plan Preparation	\$10,000 - \$15,000
Operator Service On-Line Recordkeeping	\$3,000
Personnel Qualification	\$1,000 - \$5,000 (initial)
Personnel Recordkeeping	\$2,000 (assumed 20 individuals)
Personnel Requalification	As Needed

SUBPART H - CORROSION CONTROL

Cost impacts will be incurred by operators due to this Subpart. Many of the requirements are similar to industry practice and professional standards. It is believed that many operators cathodically protect their pipelines due to control external corrosion due to potential corrosive soils, product value, environmental liability, lost revenue and downtime in the event of a leak. Nationwide, corrosion is the second highest cause of pipe failures after third-party damage. PHMSA recognized the time and cost may be required for Phase I low stress pipeline facilities to come into conformance with this Subpart.

§ 195.563 - Cathodic Protection Requirements

The number of affected cathodically unprotected pipeline segments, breakout tank areas, and pumping stations potentially affected is not known. Operators may already have such facilities cathodically protected in accordance with this Subpart, ASME B31.4 and NACE standards. Cost for cathodic protection installations will be dependent upon each facility. Due to several variables, the spread for upgrading or installing new cathodic protection (CP) systems is wide. They could range from \$5,000 to \$50,000 per mile for mainlines. The retrofitting a single small breakout tank up to 30-foot in diameter for tank bottom cathodic protection is estimated at \$15,000 to \$30,000. Operator will need to demonstrate in accordance with API RP 651 why breakout tank bottoms are not cathodically protected.

§ 195.557 - External Corrosion Control for Buried or Submerged Pipelines

No cost impact is anticipated for external corrosion control for buried or submerged pipelines.

§ 195.567 - Test Lead Installation

Test stations and leads are installed at intervals frequent to enough to obtain electrical adequacy of the cathodic protection, at casings to determine the isolation of the casing from the carrier pipe, or at points in proximity of potentially foreign structures or utilities to determine potential interference. For rural pipelines, they are generally spaced at one-mile intervals at accessible locations. Cost estimate for test lead installation is \$350 per occurrence. Additional cost may be required for excavation, ROW personnel support, property damages and potential site reclamation.

§ 195.569 - Exposed Portions of Buried Pipelines

If the operator is aware that any portion of a buried pipeline is exposed, the exposed portion must be inspected for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion is found needing corrective action under then §195.585, the pipe must be investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion. This section is primarily applicable for third-party excavations. Operator will normally be notified by One-Call system. Additional cost may be imposed on the third-party excavator to make the excavation safe for entry the operator's technician to inspect the pipeline and take remedial action.

Potential cost per excavation for an operator technician to monitor and inspect exposed buried pipe is $600 to $800 per occurrence. Estimated annual cost to monitor excavator activities and inspect pipe is $5,000 per year for each pipeline segment.

§ 195.573 - Monitoring External Corrosion Control

As a result of this subpart, the operator will need to establish a cathodic protection program and hire, train and qualify employees or use contract personnel to test and demonstrate the adequacy of cathodic protection system. Most pipelines should have cathodically protected by galvanic anodes or impressed current. If the pipeline is not cathodically protected, additional surveys or installation of a cathodic protection may be required.

Initial key elements include setting up annual monitoring program, determining whether a close-interval survey (CIS) or equivalent is required to accomplish the objectives is paragraph 10.1.1.3 of NACE Standard RP 0169. In addition, operators will need to check the performance of rectifiers at least 6 times per year for impressed current systems. Operators will need to review available maps and records, maintenance and leak history, cathodic protection reports, potential USA impacts and vulnerability, and potential damage by third parties, and site verifications. Estimated cost per pipeline segment is $5,000 to $10,000 per pipeline segment. Annual test station surveys are estimated to cost $3,000 to $5,000.

Cost for a CIS field survey is estimated at $500 to $900 per mile. There will be additional analyst report and cost. Depending upon the results of the survey, direct examination of the pipe, modification of the cathodic protection system, or alternative survey methods may be required.

§ 195.575 - Isolation of Facilities, Inspections, Tests and Safeguards

The potential significant costs for analysis and mitigation of this section are those pipelines laid longitudinally in a high–voltage electrical transmission corridor. Analysis includes review of records, coordination with the power company and field data collection. Possible costs for a 10-20 mile pipeline within a high-voltage electrical transmission corridor are provided below.

Exhibit 3-13: Costs for Pipelines within High-Voltage Electrical Transition Corridors

Data Gathering	$50,000 ($4000 - $5000 per mile)
Design	$50,000 - $125,000
Installation	$250,000 - $300,000

Other analysis and inspections include isolation of the electrical power unit of motor-operated valves from cathodically-protected the pipeline and checking the adequacy of insulating flange gaskets and fittings.

§ 195.579 - Internal Corrosion Control Mitigation

Operators will be obligated to determine whether hazardous liquids could potentially internally corrode the pipeline including breakout tanks and take necessary steps to mitigate such corrosion. If inhibitors are used, then internal corrosion coupons or other monitoring devices must be used. Potential internal corrosion risk analysis includes review of:

- Commodity type
- Operating conditions
- Topography
- Potential corrosion contaminants
- Pipe configuration and material specifications
- Leak history and analysis
- In- facility pipe and fitness of service surveys (direct assessments)
- In-service and out-of-service API 653 tank inspections
- Product analysis of potential corrosive materials
- Microbial Analysis
- ILI results for internal corrosion
- Operations practices
- Upstream environment

Mitigation measures include API 653 in-service and out-of-service breakout tank inspections, tank bottom coating, tank dewatering, product quality sampling and analysis, ILI assessments, installation of corrosion coupons and probes, use of corrosion inhibitors and biocides, periodic review and evaluation of corrosivity, and corrective action. API 653 inspections can establish an out-of-service tank inspection frequency. Representative initial costs include per pipeline segment include those in the exhibit below.

Exhibit 3-14: Costs for Pipelines within High-Voltage Electrical Transition Corridors

Internal Corrosion Mitigation	**Cost**
Initial Study and Recommendations	$10,000
Field Sampling and Investigation	$10,000 - $15,000
API Out-of-Service Breakout Tank Inspection*	$6000 -- $12000 (per tank)
Tank Floor Coating*	$30000 (includes tank cleaning)
Installation of Corrosion Coupons or Other Monitoring Equipment	$5000 - $7500 per installation (as needed)
Other Measures (Corrosion Inhibitor Injection Pumps, Launchers and Receivers for Pigging Operations)	As required
Annual Monitoring Program	$5000 - $10,000

** Tank Diameters less than 50 feet. Tank degassing and removal from service cost not included.*

Some operators may also need to initiate corrosion inhibition programs for crude oil pipeline systems pending further analysis. Others with downstream corrosive products may not be initiate inhibitor programs but will need to assess internal corrosion potential by other means as may be expected by the existing downstream regulated pipeline sector.

§ 195.581 - Atmospheric Corrosion Protection

Although reports are only required once every three years, if the operator does not instituted an aboveground pipe and breakout tank painting maintenance program to control atmospheric corrosion, there may be a significant cost impact dependent upon the extent of aboveground pipe and breakout tanks that may be involved. Nominal cost as a result of operator inspection of pipe at soil-air interfaces and appropriate remediation is expected.

§ 195.585 - Corroded Pipe Correction

No cost impact is expected by this section since repair, replacement or pressure reduction is in accordance with recognized good practice.

§ 195.589 - Corrosion Control Information

Records must be maintained for a minimum of 5 years unless otherwise specified elsewhere in Part 195. Cost impact of recordkeeping practices is expected to be minimal.

PART 199 - DRUG AND ALCOHOL TESTING

Operators of pipeline systems that become regulated under Part 195 are also subject to the requirements prescribed in 49 CFR 199. Part 199 requires that operators of pipelines test personnel for the use of prohibited drugs and the misuse of alcohol. Covered personnel subject to testing are those who perform a regulated operation, maintenance, or emergency-response on a regulated pipeline. Operators must ensure that contractors that perform such tasks must also comply. The cost for compliance includes:

- Development of a testing plan
- Testing and implementation
- Recordkeeping
- Reporting

The initial and recurring costs are dependent whether the operator (1) has a drug and alcohol plan and covered employees and associated contract personnel are already covered under appropriate plans recognized by the operator, (2) needs to add covered employees to an existing plan and inform associated contractor of requirements, or (3) needs to create a drug and alcohol plan and inform associated contract personnel of required compliance. The cost impact ranges from no impact, to the equivalent cost of adding "new employees" to a plan, and finally to a "grass-roots" program. The initial costs are based upon a contract administrator of the plan. There will be additional annual costs for random drug testing, and operator and contractor administrative and human resources personnel for implementation of the program.

Exhibit 3-15: Drug and Alcohol Testing Costs

Cost Category	Cost
New Operator D&A Plan	$800
Initial Employee Registration	$2,000 (20 employees assumed)
Additional Employees	$150 per employee
Drug Program Administration	Nominal Cost and Overhead

Other Agency Regulation

Due to PHMSA's regulation, there may a be a cost impact for creating, modifying and filing OPA 90 Plans, SPCC Plans, State Aboveground Tank and other compliance plans for facilities previously regulated by other agencies and obtaining acceptance of the plans.

Intrastate Pipelines

Cost impact on intrastate pipeline operators will be dependent upon whether existing State statutory and regulatory requirements meet or exceed the proposed Phase II requirements.

Audit Inspections

Operator cost for two-day PHMSA or authorized State agency for operations and maintenance audit in three-year or more often cycles to review operator records will be incurred. For new operators, there may be cost for follow-up responses to address deficient items found during an initial audit. There will be likely an indirect operator personnel cost for an initial 4-5 day integrity management audit for new operators with pipeline regulatory personnel. Outside consultants may be needed to assist new operators. For existing operators, audit time will likely be less since such newly regulated pipelines will likely be incorporated into existing pipeline integrity management programs.

Agency Cost

Cost impacts for PHMSA and certified State agencies for implementation of the proposed rule are not included. PHMSA and applicable agencies will need to assess the cost impact on regulatory resources.

Cost Impacts for New Rulemaking

Cost impact on Phase II pipeline operators due to future PHMSA rulemaking is not included.

Summary

The independent engineering assessment included a review of the Volpe Center survey results to assess the incremental Phase II regulatory cost impact on those operators. The study team analyzed the data and contacted many of the respondents to clarify their submissions. In total, 20 operators responded to the survey. Upon review of the data, the study team verified that 12 of the operators had low stress hazardous liquid pipelines that could be subject to Phase II regulation. The operators that examined for this analysis were:

1. Praxair, Inc.
2. BMC Holdings, Inc.
3. ExxonMobil US Production, a division of Exxon Mobil Corporation
4. ConocoPhillips Alaska, Inc.
5. Montana Refining Company, Inc.
6. Shell Pipeline Company, LP
7. DCP Midstream
8. Holly Energy Partners
9. ConocoPhillips Pipe Line
10. Oiltanking Houston L.P.
11. BP
12. Marathon Pipe Line LLC
13. Sunoco Pipeline LP
14. ExxonMobil Pipeline Company
15. Mobil Pipe Line Company
16. Plains All American Pipeline, L.P.
17. McCain Pipeline Company
18. MarkWest Michigan Pipeline L.L.C.
19. Westlake Petrochemicals
20. Chevron Pipe Line Company

Additionally, the Independent Petroleum Association of America (IPAA) was contacted to obtain any updates or revisions to pipeline mileage and compliance cost information submitted to PHMSA under the Phase I rulemaking. However, IPPA did not provide a response.

There are many reasons why there are differences between the mileage data collected by Volpe Center and the data used in the independent engineering assessment. In some cases, the unregulated low stress mileage submitted to the Volpe Center survey was preliminary. In accordance with the new Subpart B reporting requirements, several operators reassessed their data. In addition, certain operators had interpreted the Q.6 question differently.[16] Some included only the Phase I mileage and others included both Phase I and II mileage. Some operators also included HVL pipeline mileage that they operate as a low stress. Since PHMSA already regulates these pipelines, the survey instructed operators not to include this mileage. Phase II mileage that was included in the analysis was 550.5 miles. Approximately 69 percent of the mileage carries crude oil. The survey responses indicate that initial incremental cost of regulation is estimated at $27,800 per mile with a wide spread from no impact to $76,300 per mile. A small mileage and large operator are at the upper end of the spectrum. At this time, the analysis is subject to revision depending upon additional responses from operators.

The analysis estimates the initial and recurring costs for each of the Part 185 subparts based upon discussions with operators, internal cost data, and review of historical incident distributions for low stress pipelines by commodity transported. The wide distribution of results found by the analysis is due to operator practices, industry, mileage differences between operators, and commodity transported. One operator advised of potential considerable regulatory cost exposure due to acquisition of previously unregulated pipelines from other operators.

For those operators that would be subject to incremental cost such as integrity management program or public awareness program, the analysis collected such costs at a prescribed frequency. If the operator did not know the cost of such programs, the analysis used internal engineering cost data.

The analysis also allocated costs for each of the subparts to the appropriate incident categories. Again, the analysis made these determinations based upon discussions with operators, internal cost data, and review of historical incident distributions for low stress pipelines and commodity transported.

In total, 20 pipeline operators were contacted. Twelve of the operators that responded to the survey had low stress pipelines that could be subject to the Phase II rulemaking and provided cost information. Exhibit 3-16 provides the detailed costs reported by these 12 pipeline operators. The strength of this data is the coverage of a sample of pipeline operators with detail by subpart of the regulation. Organizing the pipeline operators by the diameter and location of their pipelines allows development of costs for the different parts of the unregulated population of pipelines. In total, these data represent approximately half of the estimated mileage of unregulated low stress pipelines.

[16] This question asked, "What are the total number of miles of rural low stress hazardous liquid transmission pipeline your company operates within one-half mile of an unusually sensitive area?"

Exhibit 3-16: Reported Phase II Pipeline Mileages & Compliance Costs By Firm

Operator Name	Compliance with Part 195: Percent Substantially in Compliance	Percent Out of Compliance	Phase II Mileage: Total	≥ 8 5/8" USA	≥ 8 5/8" non-USA	< 8 5/8" non-USA	Initial Cost by Subpart: Subpart A	Subpart B	Subpart F	Subpart G	Subpart H	Part 199 Drug & Alcohol	Total Initial Cost	Initial Phase II Cost per Mile	Total Recurring Costs: Every Year	Every 5 Years	Recurring Costs Subpart Allocation	Recurring Costs (per mile): Every Year	Every 5 Years
Data by Individual Operator																			
Praxair, Inc.			0	0	0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -			
BMC Holding, Inc.			0	0	0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -			
ExxonMobil US Production	100%		2.7	0	0	2.7	$ 137,000	$ -	$ 27,000	$ -	$ 15,000	$ -	$ 179,000		$ 2,000	$ -	100% Subpart F – IMP		
ConocoPhillips Alaska, Inc.	100%		32.8	32.8	0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -			
Montana Refining Company, Inc.			0	0	0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -			
Shell Pipeline Company, LP			0	0	0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -			
DCP Midstream			0	0	0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -			
Holly Energy Partners	100%		30.3	0	18.8	11.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -			
ConocoPhillips Pipe Line	100%		24.0	0	24.0	0	$ 5,000	$ -	$ -	$ 10,000	$ -	$ -	$ 15,000		$ 3,000	$ -	100% Subpart G		
Oiltanking Houston L.P.			0	0	0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -			
BP*	100%		2.8	0.9	0.9	0.9	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -			
Marathon Pipe Line LLC*		100%	82.9	78.6	4.4	0.0	$ 5,000	$ -	$ 640,000	$ -	$ -	$ -	$ 645,000		$ -	$ 268,000	100% Subpart F – IMP		
Sunoco Pipeline LP*		100%	45.0	15.0	15	15	$ -	$ -	$ 500,000	$ -	$ -	$ -	$ 500,000		$ -	$ 500,000	100% Subpart F – IMP		
ExxonMobil Pipeline Company			0	0	0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -			
Mobil Pipe Line Company			0	0	0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -			
Plains All American Pipeline, L.P.		100%	178.7	0.0	178.7	0	$ 5,000	$ -	$ 143,000	$ -	$ 13,484,100	$ -	$ 13,632,100		$ 564,500	$ 5,691,200	$268,000 – Subpart A per year $140,000 – Subpart F per year $156,500 – Subpart H per year $5,691,200 – Subpart H every 5 years		
McCain Pipeline Company		100%	4.0	4.0	0	0	$ 335,000	$ -	$ 125,000	$ -	$ 15,000	$ -	$ 475,000		$ -	$ 100,000	100% Subpart F – IMP		
MarkWest Michigan Pipeline L.L.C.	100%		100.0	0	100.0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -			
Westlake Petrochemicals		100%	6.3	4.0	2.3	0	$ 5,000	$ -	$ 106,500	$ -	$ 10,000	$ -	$ 121,500		$ -	$ 100,000	100% Subpart F – IMP		
Chevron Pipe Line Company	100%		37.0	0	37.0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -			
Totals for Regulatory Subgroups																			
Total < 8,5/8 " USA	0.25	0.75		135.2									$ 1,728,651	$ 12,781	$ -	$ 968,000		$ -	$ 7,157
Total ≥ 8,5/8 " non USA	0.47	0.53			381.0								$ 13,659,949	$ 35,852	$ 567,500	$ 6,258,700		$ 1,489	$ 16,427
Total < 8,5/8 " non USA	0.49	0.51				30.1							$ 179,000	$ 5,941	$ 2,000	$ 2,000		$ 66	$ 66
All Miles	0.42	0.58	546.4																

* These operators only inidicated total low stress mileage. Mileage segments for these companies are assumptions based on additional data.

The top section of Exhibit 3-11 provides data by individual operator. The first column in this section provides the operator name, followed by two columns which describe the pipeline in terms of whether it is substantially in compliance or out of compliance. The next four columns provide mileages subject to Phase II – both totals and mileages by diameter and USA status. The remaining columns provide data on costs, starting with initial costs and initial costs per mile, followed by recurring costs and recurring costs per mile.

The second section of Exhibit 3-11 summarizes the data by regulatory subgroup, which is defined by diameter and USA status. These data are simply summations of the data based on each pipelines regulatory status. For example, there are 135.2 miles of small diameter pipe inside USA. This includes the mileage of Conoco Phillips Alaska, Inc., most of the mileage of Marathon Pipeline LCC, a third of the mileage of Sunoco Phillips, the mileage of McCain Pipeline Company and 4 miles of Westlake Petrochemicals. The costs for each regulatory subgroup is provided to the right of listed mileages, in categories of total initial cost, initial cost per mile, total recurring costs and recurring costs per mile. For example, the total initial cost of low stress pipeline less than 8, 5/8" and within ½ mile of an USA is $1,728,651. However, this is not a simple summation of total initial costs of individual pipeline operators in the applicable column cells above, because some operators have mileage in multiple regulatory subgroups. Westlake Petrochemicals has 4.0 miles of less than 8, 5/8" and within ½ mile of an USA pipe and 2.3 miles of greater than 8, 5/8" and outside ½ mile of an USA pipe. The total initial cost of Westlake Petrochemicals for the regulatory subgroup less than 8, 5/8" and within ½ mile of an USA is calculated as follows: ($5,000 + $6,500 + $10,000)*(4.0/6.3) + $100,000 = $113,651. Westlake Petrochemical's Subpart A cost is $5,000, Subpart F cost not related to IMP is $6,500, and Subpart H cost is $10,000. These costs are added and weighted by the respective mileage. The IMP cost of $100,000 is added but not weighted because IMP costs only apply to this regulatory subgroup (pipeline less than 8, 5/8" and within ½ mile of an USA). This method of weighting Subpart costs for mileages and adding or excluding IMP costs was repeated for each operator to determine the total initial and recurring costs for each regulatory subgroup.

The per mile initial and recurring costs is a simple division of total initial and recurring costs by the collected regulatory subgroup mileages. For example, the total every year recurring cost for the regulatory subgroup of pipeline greater than 8,5/8" and outside ½ mile of an USA is $567,500. The total sample mileage for this subgroup is 381.0 miles. Therefore, the per mile every year recurring cost for the regulatory subgroup of pipeline greater than 8, 5/8" and outside ½ mile of an USA is $1,489 ($567,500/381.0).

3.4 Summary of Compliance Costs

The Phase I regulatory costs estimates were derived from the summary of compliance costs in the PHMSA 2007 Regulatory Analysis summarized in Exhibit 3-2. The cost stream summarized in the exhibit was turned into a net present value cost per mile. Only 7.26 percent of integrity management plan costs were factored into the estimate since that is the percentage of low stress pipeline that are estimated to be within ½ mile of an USA and thus applicable to this analysis. The strength of this data is that is was collected by subpart of the regulation and includes initial and recurring costs. However, it was collected in 2003 and largely represents cost estimates submitted by one company for gas pipelines. The association that originally provided the data did not have any more up-to-date or complete estimates. In addition, this Phase I data was not available by pipe diameter.

The Volpe Center regulatory cost estimates were derived from the most readily usable data in the Volpe Center pipeline operator survey summarized in Exhibit 3-3. The most readily usable data in the survey came from MarkWest, Plains All American Pipeline, Marathon, and ConocoPhillips. The cost estimates provided by these firms were assumed to be initially year costs per mile. The cost stream of the subsequent years was assumed to be similar in ratio to the most detailed estimates provided in the Phase I regulatory evaluation. The strength of this data is that it reports current costs for actual current operators of unregulated low stress hazardous liquid pipelines. Data are available for the major parts and subparts of the proposed regulation. However, the data are not separated between initial and recurring costs which makes them difficult to interpret. With only four responses it is difficult to separately estimate costs by pipe diameter and by proximity to an USA.

The most accurate and up-to-date estimation of Phase II compliance costs comes from the independent engineering analysis as shown in Exhibit 3-16. These figures were derived largely from follow-up with pipeline operators and analysis of the Volpe Center survey. Of the 20 pipeline operators contacted, it was determined that at least 12 had applicable pipelines and compliance costs related to the Phase II rulemaking. Of these 12 pipeline operators, seven had small or no compliance costs: Exxon Mobile US, Conoco Phillips Alaska, Holly Energy Partners, Conoco Phillips Pipeline, BP, and Mark West Michigan. The remaining five operates had relatively large compliance costs: Marathon Pipeline, Sunoco Pipeline, Plains All American Pipeline, McCain Pipeline, and Westlake Petrochemicals. This finding is important for the benefit calculations in the next chapter, as separate benefit estimates are made for bringing a pipeline almost in compliance into full compliance and bringing a pipeline largely out of compliance into full compliance.

Exhibit 3-17 summarizes the initial and recurring costs by each alternative on a per mile basis. The initial and recurring per mile costs for Alternative 1 are a mileage weighted summation of per mile costs for Alternatives 2, 3 and 4.[17] The initial and recurring costs for Alternatives 2, 3 and 4 come directly from Exhibit 3-16. Alternatives 5 and 6 are calculated as a mileage weighted summation of Alternatives 2, 3 and 4 without the costs of Subpart H and the IMP.

Exhibit 3-17: Costs by Alternative

Alternative	Initial Cost (per mile)	Recurring Cost (per mile)	
		Every year	Every 5 year
1. All low stress	$ 24,601	$ 926	$ 10,516
2. Small diameter inside ½ mile of USA	$ 12,781	$ -	$ 7,157
3. Large diameter outside ½ mile of USA	$ 35,852	$ 1,489	$ 16,427
4. Small diameter outside ½ mile of USA	$ 5,941	$ 66	$ 66
5. All except Subpart H	$ 2,922	$ 676	$ 1,196
6. All except the IMP	$ 23,873	$ 926	$ 9,996

To derive total costs, the per mile costs in Exhibit 3-17 are multiplied by the estimated mileages (in bold) in Exhibit 2-6. These mileages, again, are: Alternative 1 – 1,384.3, Alternative 2 – 100.5, Alternative 3 – 840.6, Alternative 4 – 443.2, Alternative 5 – 1,384.3, and Alternative 6 – 1,384.3 In order to be meaningful, a benefit-cost analysis must not only express all benefits and costs in monetary terms, it must also account for the change in the value of the dollar over time. Exhibit 3-18 provides tables deriving the 30 year total present value costs for each alternative. The interest rate used to discount future cost outlays in this analysis is 2.7 percent. The real discount rate was taken from a memorandum by the Executive

[17] For example, the initial per mile cost of Alternative 1 is calculated as $12,781*(100.5/1,384.3) + $25,852*(840.6/1,384.3) + $5,941*(443.2/1,384.3) = $24,601.

Office of the President updating Appendix C of the OMB's Circular No. A-94 (Revised December 2008) entitled "Discount Rates for Cost-Effectiveness, Lease Purchase, and Related Analyses.[18]

The estimated total 30 year present value compliance costs for each alternative in millions of dollars are provided in bold at the bottom of each table. The first column provides the year, the second column provides the nominal per mile compliance cost for each year (all provided in Exhibit 3-17) and the third column provides the present value per mile compliance cost for each year when an annual discount rate of 2.7 is applied.

[18] Memorandum from Executive Office of the President, Office of Management and Budget. "Discount Rates for OMB Circular No. A-94. December 12, 2008. http://www.whitehouse.gov/omb/assets/omb/memoranda/fy2009/m09-07.pdf

Exhibit 3-18: 30 Year Present Value Cost Tables by Alternative

Alternative 1

Year	Per Year Per Mile Cost	Per Year Per Mile PV
1	24,601	24,601
2	926	901
3	926	878
4	926	855
5	926	832
6	10,516	9,204
7	926	789
8	926	768
9	926	748
10	926	728
11	10,516	8,056
12	926	691
13	926	672
14	926	655
15	926	638
16	10,516	7,052
17	926	604
18	926	589
19	926	573
20	926	558
21	10,516	6,172
22	926	529
23	926	515
24	926	502
25	926	488
26	10,516	5,402
27	926	463
28	926	451
29	926	439
30	926	427
Per Mile 30 Year PV		75,781
Eligible Mileage		1384.3
Total 30 Year PV Cost (In Millions)		**104.9**

Alternative 2

Year	Per Year Per Mile Cost	Per Year Per Mile PV
1	12,781	12,781
2	-	-
3	-	-
4	-	-
5	-	-
6	7,157	6,265
7	-	-
8	-	-
9	-	-
10	-	-
11	7,157	5,483
12	-	-
13	-	-
14	-	-
15	-	-
16	7,157	4,799
17	-	-
18	-	-
19	-	-
20	-	-
21	7,157	4,201
22	-	-
23	-	-
24	-	-
25	-	-
26	7,157	3,677
27	-	-
28	-	-
29	-	-
30	-	-
Per Mile 30 Year PV		37,206
Eligible Mileage		100.5
Total 30 Year PV Cost (In Millions)		**3.7**

Alternative 3

Year	Per Year Per Mile Cost	Per Year Per Mile PV
1	35,852	35,852
2	1,489	1,450
3	1,489	1,412
4	1,489	1,375
5	1,489	1,339
6	16,427	14,378
7	1,489	1,269
8	1,489	1,236
9	1,489	1,204
10	1,489	1,172
11	16,427	12,585
12	1,489	1,111
13	1,489	1,082
14	1,489	1,053
15	1,489	1,026
16	16,427	11,015
17	1,489	973
18	1,489	947
19	1,489	922
20	1,489	898
21	16,427	9,641
22	1,489	851
23	1,489	829
24	1,489	807
25	1,489	786
26	16,427	8,439
27	1,489	745
28	1,489	725
29	1,489	706
30	1,489	688
Per Mile 30 Year PV		116,517
Eligible Mileage		840.6
Total 30 Year PV Cost (In Millions)		**97.9**

Alternative 4

Year	Per Year Per Mile Cost	Per Year Per Mile PV
1	5,941	5,941
2	66	65
3	66	63
4	66	61
5	66	60
6	66	58
7	66	57
8	66	55
9	66	54
10	66	52
11	66	51
12	66	50
13	66	48
14	66	47
15	66	46
16	66	45
17	66	43
18	66	42
19	66	41
20	66	40
21	66	39
22	66	38
23	66	37
24	66	36
25	66	35
26	66	34
27	66	33
28	66	32
29	66	31
30	66	31
Per Mile 30 Year PV		7,264
Eligible Mileage		443.2
Total 30 Year PV Cost (In Millions)		**3.2**

Alternative 5

Year	Per Year Per Mile Cost	Per Year Per Mile PV
1	2,922	2,922
2	676	659
3	676	641
4	676	624
5	676	608
6	1,196	1,047
7	676	576
8	676	561
9	676	546
10	676	532
11	1,196	916
12	676	504
13	676	491
14	676	478
15	676	466
16	1,196	802
17	676	442
18	676	430
19	676	419
20	676	408
21	1,196	702
22	676	387
23	676	376
24	676	366
25	676	357
26	1,196	614
27	676	338
28	676	329
29	676	321
30	676	312
Per Mile 30 Year PV		18,175
Eligible Mileage		1,384.3
Total 30 Year PV Cost (In Millions)		**25.2**

Alternative 6

Year	Per Year Per Mile Cost	Per Year Per Mile PV
1	23,873	23,873
2	926	901
3	926	878
4	926	855
5	926	832
6	9,996	8,749
7	926	789
8	926	768
9	926	748
10	926	728
11	9,996	7,658
12	926	691
13	926	672
14	926	655
15	926	638
16	9,996	6,703
17	926	604
18	926	589
19	926	573
20	926	558
21	9,996	5,867
22	926	529
23	926	515
24	926	502
25	926	488
26	9,996	5,135
27	926	463
28	926	451
29	926	439
30	926	427
Per Mile 30 Year PV		73,280
Eligible Mileage		1,384
Total 30 Year PV Cost (In Millions)		**101.4**

4. TRADITIONAL BENEFITS

Introduction

PHMSA expects the proposed rulemaking to reduce the number of incidents and the incident costs and consequences. Data on incident costs, which PHMSA traditionally collects, include property damage, product loss, environmental damage, and environmental spill cleanup activities. The ability of the proposed rulemaking to reduce or avoid these costs are considered to be the primary benefit of the rulemaking and are referred to as traditional benefits. Data on incident costs for low stress pipelines are generally not available by virtue of the fact that PHMSA has not regulated these pipelines in the past. Moreover, the reduction in costs that the rulemaking would cause is also unknown. Therefore, as part of this regulatory analysis, several data sources and approaches are examined in order to evaluate the potential avoided costs. These approaches include:

1. Utilization of data from the 1990 ANPRM / Low-stress Phase I
2. Compilation of PHMSA's 7000-1 data for low stress pipelines
3. Collection of data from individual states
4. Collection of data from other countries
5. Time series trend-line analysis
6. Collection of industry data

An examination of the costs and current levels of compliance for individual pipelines, as discussed in Section 3.3, revealed that pipelines fell into two distinct subgroups. The first group of pipelines was generally in compliance with the regulations and faced small costs in order to comply with the proposed rulemaking. The second group of pipelines did not currently comply with the rulemaking and faced significant costs in order to comply with the proposed rulemaking. With this in mind, it is important to estimate the benefits for bringing a pipeline that is substantially in compliance into full compliance and bringing a pipeline that is substantially out of compliance into full compliance. Assigning benefits in this manner is effective for weighting the mileage by expected benefits. After each approach above was used, it was determined that a combination of approaches 1 and 2 provide a good estimate of the benefit from regulating an out of compliance low stress pipeline, and approach 5 provides a good estimate of the benefit from regulating a low stress pipeline that is already substantially in compliance. The remainder of this chapter details each methodology and presents the resulting analysis.

4.1 Utilize data from the 1990 ANPRM / Low Stress Phase I

Method

The estimation of benefits that was used in the low stress Phase I regulatory analysis was based on data collected for the 1990 Advanced Notice of Proposed Rulemaking (ANPRM).[19] The 1990 ANPRM collected data from pipeline companies on incident costs for regulated and unregulated pipelines. In the low stress Phase I regulatory analysis, a current estimate of benefits was made by updating those estimates for inflation.

1990 ANPRM

A survey conducted for the 1990 ANPRM requested the following information from pipeline operators:

[19] "Advanced Notice of Proposed Rulemaking: Transportation of a Hazardous Liquid in Pipelines Operating at 20 percent or Less of Specified Minimum Yield Strength." U.S. Department of Transportation, Research and Special Programs Administration. Federal Registrar, Vol. 55, No. 211, Pages 45822 – 45825, October 1990.

- Low stress pipeline mileage
- The average annual cost of accidents that occurred on low stress pipelines in the years 1986-1990
- Whether or not a given pipeline is operated in compliance with Part 195

For incidents involving death and injury, the respondents to the ANPRM questionnaire were instructed to use $1.5 million as the economic value of a human life and $450,000 as the cost to society of an injury requiring hospitalization.

1992 Economic Evaluation

In 1992, the Volpe National Transportation Systems Center conducted an "Economic Evaluation of Regulating Certain Hazardous Pipelines Operating at 20 percent or Less of Specified Minimum Yield Strength."[20] The approach taken in the evaluation was as follows:

- Estimate the accident costs per mile per year for low stress pipelines that are not in compliance with Federal Pipeline Safety Regulation 49 CFR Part 195
- Estimate the accident costs per mile per year that can be expected after the proposed regulatory change is implemented
- Calculate the difference between these two accident cost estimates

The range of low stress lines Volpe analyzed included HVL pipelines operating at 20 percent or less of SMYS and non-HVL operating within 220 yards of populated areas or over or under navigable waterways at 20 percent or less of SMYS. Volpe concluded it was cost beneficial to bring these low stress pipelines into compliance with Part 195.

Exhibit 4-1 shows the 1992 Economic Evaluation estimated cost per mile per year of low stress lines in compliance and not in compliance, and the associated benefit from regulation. All dollar figures used and calculated in the original 1992 economic evaluation were given in 1991 dollars.

Exhibit 4-1: 1992 Economic Evaluation Cost and Benefit Estimates (in 1991 dollars)

Cost per mile per year **not in** compliance	$3,692
Cost per mile per year **in** compliance	$105
Benefit per mile per year	$3,587

The ANPRM questionnaire reported that the per year cost of incidents on 266 miles of low stress pipeline in compliance was $28,000. Therefore, the per mile per year estimate of costs for low stress pipelines in compliance with Part 195 in 1991 dollars was $105.

The accident cost per mile per year for unregulated low stress lines impacted by the regulation was calculated under the following assumption: an accident the size of the Arthur Kill pipeline accident would occur, on average, once every ten years. As reported on the ANPRM questionnaire, the per year cost of incidents on 1,565 miles of low stress pipeline not in compliance with Part 195 (including the annualized cost of an incident the size of Arthur Kill) was $5,776,000. Therefore, the cost per mile per year estimate of low stress lines not in compliance was $3,692.

[20] "Economic Evaluation of Regulating Certain Hazardous Pipelines Operating at 20 percent or Less of Specified Minimum Yield Strength," by Deanna Mirsky (EG&G/Dynatrend) and The Hazardous Materials Transportation Special projects Office VNTSC. July 21, 1992. Docket: PHMSA-RSPA-2003-15864-0034

The difference between the cost per mile for lines not in compliance and lines in compliance is the estimated benefit from regulation. In the 1992 Economic Evaluation, this benefit was $3,587.

2007 Phase I Regulatory Analysis

The per mile benefit of the Phase I rulemaking was calculated in the 2007 Phase I Regulatory Analysis[21] review of the cost and benefit estimates derived in the 1992 Economic Evaluation. These figures were updated for inflation (to 2006 dollars) using the Implicit Price Deflators for Gross Domestic Product.[22]

No attempt was made in Phase I to update the dollar values for loss of life and injury. Although no explanation was given as to why these numbers were not updated, it is likely because the frequency of death and injury for the low stress spills was low. For the years 2002-2008, there are no reported deaths or injuries on the 7000-1 database for low stress lines.

Exhibit 4-2 shows the inflation-updated cost estimates of the ANPRM data for the 2007 Phase I Regulatory Analysis.

Exhibit 4-2: 2007 Phase I Regulatory Analysis Inflation Updates (in 2006 dollars)

Cost per mile per year **not in** compliance	$4,969
Cost per mile per year **in** compliance	$141
Benefit per mile per year	$4,828

The benefit per mile estimate for the Phase I Regulatory Analysis is inflation-updated from $3,587 to $4,828.

2009 Phase II Regulatory Analysis

Updating the original estimates solely for inflation again for the Phase II Regulatory Analysis results in the estimates provided in Exhibit 4-3.

Exhibit 4-3: 2009 Phase II Regulatory Analysis Inflation Updates (in 2008 dollars)

Cost per mile per year **not in** compliance	$5,391
Cost per mile per year **in** compliance	$153
Benefit per mile per year	$5,238

After adjusting for inflation, the current per year per mile benefit from regulation figure for the Phase II Regulatory Analysis is $5,238.

Exhibit 4-4 gives a comparison of the costs and associated benefits for each analysis using the inflation update approach.

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[21] "Regulatory Analysis; Pipeline Safety: Protecting Unusually Sensitive Areas from Rural Onshore Hazardous Liquid Gathering Lines and Low Stress Lines." U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. September 2007, Docket No. RSPA-2003-158

[22] "Table 1.1.9. Implicit Price Deflators for Gross Domestic Product." Bureau of Economic Analysis, September 30, 2009. http://www.bea.gov/national/nipaweb/TableView.asp?SelectedTable=13&ViewSeries=NO&Java=no&Request3Place=N&3Place=N&FromView=YES&Freq=Year&FirstYear=1990&LastYear=2009&3Place=N&Update=Update&JavaBox=no#Mid

Exhibit 4-4: Comparison of Estimates

Type of Estimate	1992 Economic Evaluation	2007 Phase I	2009 Phase II
GDP Deflator	74.76	100.00	108.48
Cost per mile per year **not in** compliance	$3,692	$4,969	$5,391
Cost per mile per year **in** compliance	$105	$141	$153
Benefit per mile per year	$3,587	$4,828	$5,238

Limitations

This method provides a good attempt to estimate the benefits from bringing a fully unregulated line into full compliance. There are two major limitations of this method. First, the data collected for the ANPRM are dated. The ANPRM questionnaire was distributed in 1990 and asked operators to report on incidents from 1986-1990. Over the past twenty years, there have been significant improvements in general pipeline operation and cleanup methods have changed. Environmental remediation, for example, is much more costly today than twenty years ago. Therefore, solely updating the ANPRM results for inflation will likely understate the benefits from regulation. Second, some of the unregulated low stress pipeline miles reported in the ANPRM questionnaire are now regulated under Phase I. Estimating benefits using the ANPRM data, therefore, will include the benefit of regulating lines that are already regulated.

In the following section, actual per mile costs for currently regulated lines are compared to the ANPRM inflation-updated regulated costs derived in this section. The difference in the figures can be treated as an estimate of the increases in costs beyond inflation. Applying this factor to the ANPRM inflation-updated unregulated cost per mile creates an estimate for current unregulated costs. This combination of ANPRM data and current PHMSA incident report statistics is one method for determining the benefits from regulation.

4.2 Compile PHMSA's 7000-1 Data for Low stress Pipelines

Database

PHMSA requires that information on every incident on regulated hazardous liquid pipelines be reported, including information on location, cause and consequence. This information can be used to assess safety trends and guided development of new initiatives to enhance hazardous materials transportation safety. These incident data present information on the regulated pipeline system.

Report Format

PHMSA F 7000-1 (1-2001; Accident Report Form) is a four-page accident report form. The associated operator files all four pages (long form report) if the incident meets any one of the following criteria:

- More than 5 barrels (bbl) lost
- Spill to water,
- Death or injury,
- Fire or explosion

For spills smaller than 5 bbl that do not include one of the above characteristics, only the first page is filed (short form report). This reporting procedure was adopted in 2002. Before 2002, incidents greater than 50 bbl were reported. Additionally, the number of possible incident causes was changed from 8 to 25, environmental impact info was added, and more overall detail was included. For consistency in reporting and a reflection of current practices, only incidents from 2002 to 2008 are analyzed in this report, and for breadth of information, only incidents on the long form are analyzed.

From 2002 to 2008, there are 2,887 incidents in the 7000-1 database. Long-form reports were filed on 1,368 due to the spill being greater than five bbl. The long-form incidents reported include 255 offshore and/or HVL incidents that are excluded because this rule making does not encompass them. This leaves 1,113 onshore, non-HVL, long form incidents to be evaluated.

Examining incidents by SMYS

There is no specified field in the 7000-1accident report form for percent SMYS, and thus no way to immediately specify stress level. Instead, the following proxy (Exhibit 4-5) developed during Phase I research[23]:

Exhibit 4-5: Percent SMYS Formula

$$PercentSMYS = \frac{InternalDesignpressure * Diameter}{2 * SMYS * Wallthickness}$$

With this proxy, 503 of the 1,113 onshore, non-HVL incidents can be classified by percent SMYS. The other 610 incidents cannot be classified by percent SMYS because one or more of the formula components are missing or inconsistent. Of the 503 classifiable incidents, 117 are low stress incidents and 386 are not low stress. Of the 386 not low stress incidents, 30 have a calculated percent SMYS exceeding 72 percent. In general, liquids operators must operate at 72 percent SMYS or lower, and therefore there is almost certainly something wrong with one of the data elements used to calculate percent SMYS in these 30 incidents. These incidents are thus excluded from any analysis incorporating percent SMYS.

Conclusively, of the 473 incidents that are 72 percent SMYS or less, onshore, non-HVL and occur between 2002 and 2008, 117 (25 percent) are low stress and 356 (75 percent) are not low stress. These incidents are used for all analyses that incorporate percent SMYS. For any analysis that does not incorporate percent SMYS, the 1,113 onshore, non-HVL, 2002-2008 incidents are used.

Per-mile Limitations

PHMSA's 7000-1.1 Hazardous Liquid Annual Report (different from the 7000-1 Accident Report) lists pipeline mileage by various categories. Unfortunately, the data is marginally distributed and not contingently distributed. For example, it is possible to tell how many miles of small diameter pipe exist and how many miles of inside high consequence areas exist, but it is not possible to tell how many miles of small diameter pipeline inside high consequence area pipe exist. This is not a problem for the Accident Report incident database – it is possible to tell if an incident was a small diameter pipeline inside high consequence area incident. However, because the miles data cannot be distributed this way, the analysis cannot convert all cost estimates to a per mile basis. For example, the analysis cannot calculate the per-mile cost of small diameter low stress pipeline incidents within high consequence areas.

To calculate per mile incident costs, the following 2008 mileage listed in Exhibit 4-6 is used:

[23] This methodology was developed and approved by PHMSA technical staff Dewitt Bordeaux of the Training and Qualifications Division and Piyali Talukdar of the Program Development Division. Acknowledgment and further explanation of proxy cited in email correspondence on 9/25/09

Exhibit 4-6: 2008 Onshore, Non-HVL Mileage

	Low Stress	Not Low Stress	HCA	Not HCA
CO2 OR OTHER	931.13	3240.66	417.92	3,753.87
CRUDE OIL	2090.69	43776.87	19307.30	26,560.25
PETROLEUM & REFINED PRODUCTS	1795.24	59098.20	32882.59	28,010.85
Grand Total	**4,817.06**	**106,115.73**	**52,607.81**	**58,324.97**

In similar data provided for 2007, there are approximately 300 less low stress miles, 500 less not low stress miles, and 1000 more HCA miles. These differences are negligible when calculating per mile cost and therefore only 2008 mileage is used.

Analysis of the Databases

Two analyses conducted using the PHMSA 7000-1 Accident Report database follow. Analysis I is a general analysis of incident statistics. It is assumed that operators do not report unregulated incidents, and it is, therefore, an analysis of regulated incidents. Analysis II uses the cost per mile figure of current regulated low stress incidents determined in Analysis I to update the estimates made in Phase I (inflation updates) for changes in methods, operation and pipeline practices.

Analysis I: All Low Stress Incidents

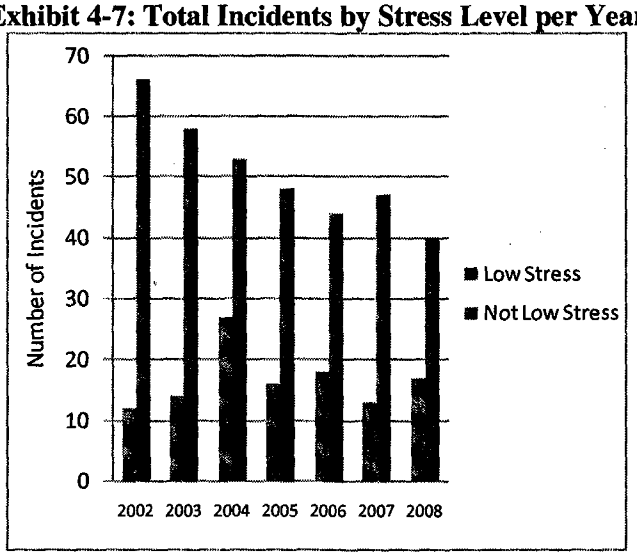
This section treats includes analysis within the group of low stress incidents, by low stress and not low stress incidents, across percent SMYS levels, and by HCA status.

Stress Level: Low Stress and Not Low Stress

For all analysis involving stress level, only data for which percent SMYS can be calculated and for which percent SMYS is within a reasonable range is used.

Exhibit 4-7 is a comparison of total incidents by stress level per year. Over the seven-year period, not low stress incidents trended downwards whereas low stress incidents remained relatively constant.

Exhibit 4-7: Total Incidents by Stress Level per Year



While there are many more not low stress incidents, there are also many more not low stress miles. Exhibit 4-8 shows number of incidents on a per thousand mile basis. The average annual number of incidents per thousand miles, Exhibit 4-9, is roughly seven times greater for low stress pipelines than not low stress.

Exhibit 4-8: Incidents per Thousand Miles

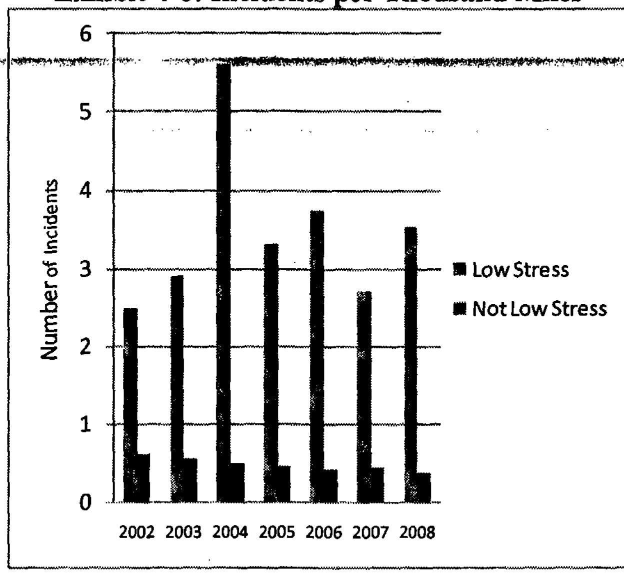
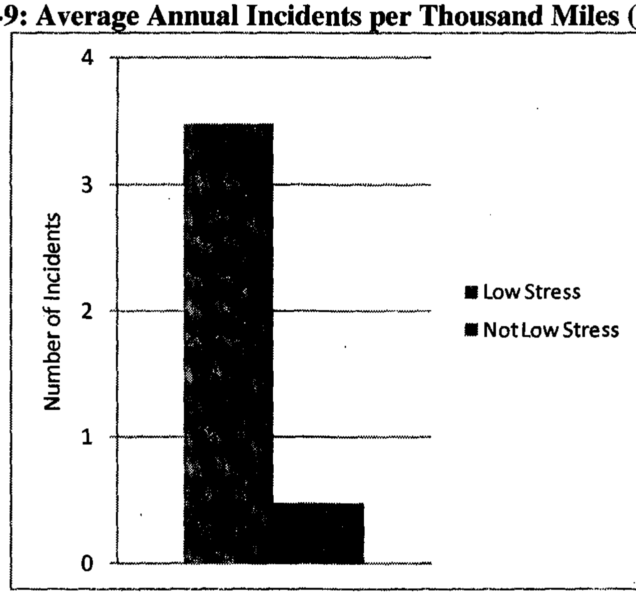


Exhibit 4-9: Average Annual Incidents per Thousand Miles (2002-2008)



Exhibits 4-10 and 4-11 show the costs per mile for low and not low stress incidents. The per mile costs vary each year, with not low stress at higher levels than low stress in three years and low stress higher than not low stress in four years, but over the entire period, the average annual cost per mile is almost $300 higher for low stress. The average annual cost per miles is $615 for low stress, and $330 for not low stress. These figures were determined as follows. The total incident cost for low stress pipeline incidents over the entire period 2002 to 2008 is $20,749,392. The respective miles of low stress pipeline, as determined in the 7000-1.1 Annual Report for 2008, is 4,817 (provided in Exhibit 4-6). Dividing the total low stress pipeline cost figure by the miles gives a total per mile cost for low stress pipeline incidents of $4,308. Dividing $4,308 by seven (2002 to 2008) gives an average annual per mile cost of low stress pipeline incidents of $615. The respective figures for other types of pipeline incidents are: total incident cost - $245,122,197; 2008 Annual Report miles – 106,116; over seven years, average annual per mile cost is $330.

Exhibit 4-10: Cost per Mile per Year

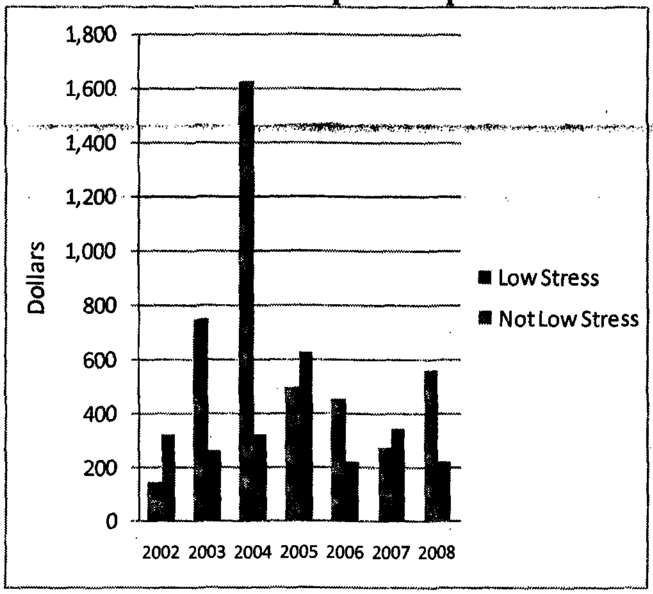
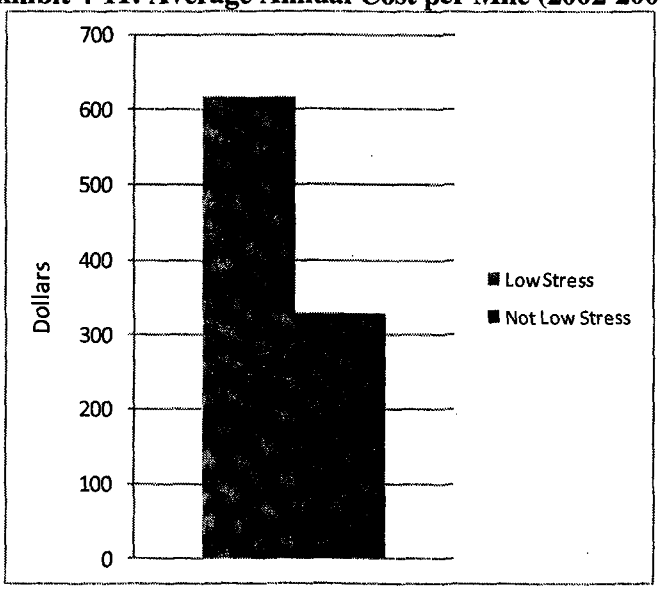


Exhibit 4-11: Average Annual Cost per Mile (2002-2008)



Exhibits 4-12 and 4-13 break out cost and net bbl lost by percent SMYS. On average, higher percent SMYS incidents tend to be more costly, both in dollars damage and net bbl lost. In other words, for any given incident, a lower percent SMYS incident tends to be less costly.

Exhibit 4-12: Cost per Incident by SMYS (in thousands) (2002-2008)

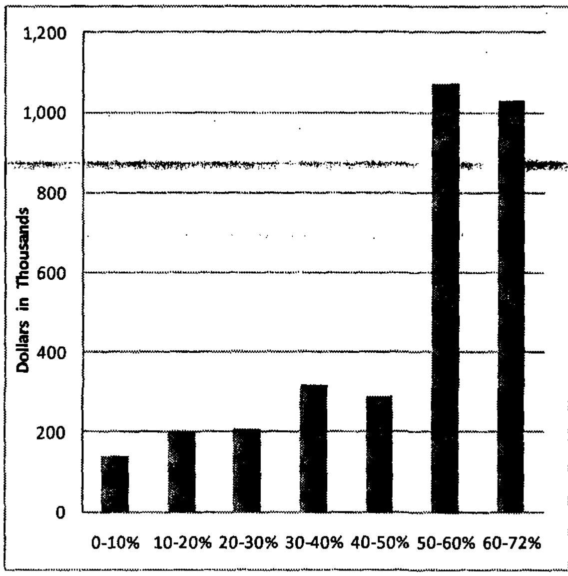
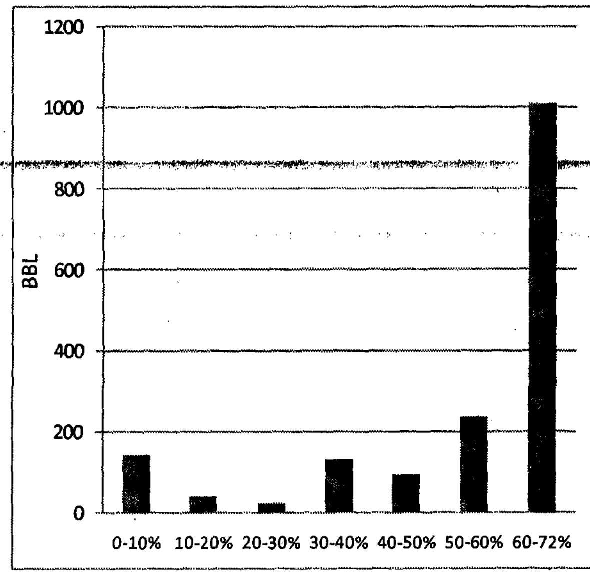


Exhibit 4-13: Net BBL Lost per Incident by SMYS (2002-2008)



The greater per incident cost for higher percent SMYS incidents is reflected in the Exhibits 4-14 and 4-15. These scatter plots show that outlying incidents with atypically high costs tend to occur at higher percent SMYS. On a per *incident* basis, not low stress incidents are more costly, but on a per *mile* basis, low stress incidents are more frequent and thus more costly per mile.

Exhibit 4-14: Cost by SMYS (2002-2008)

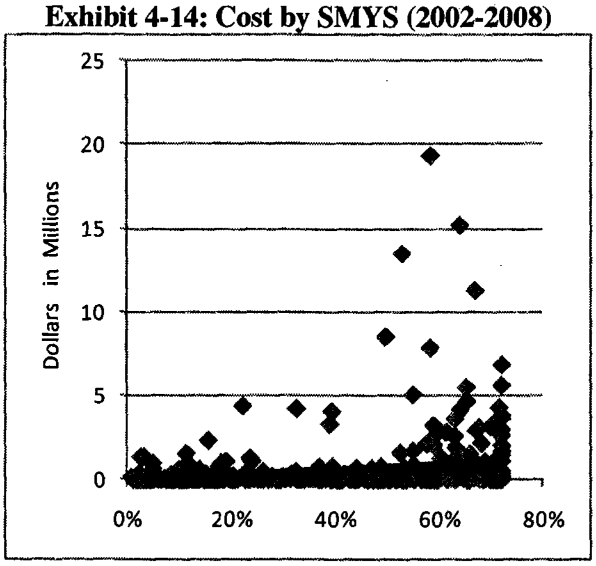
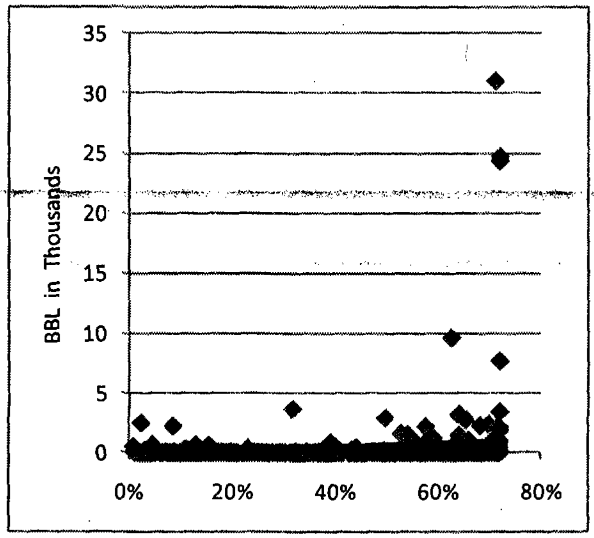


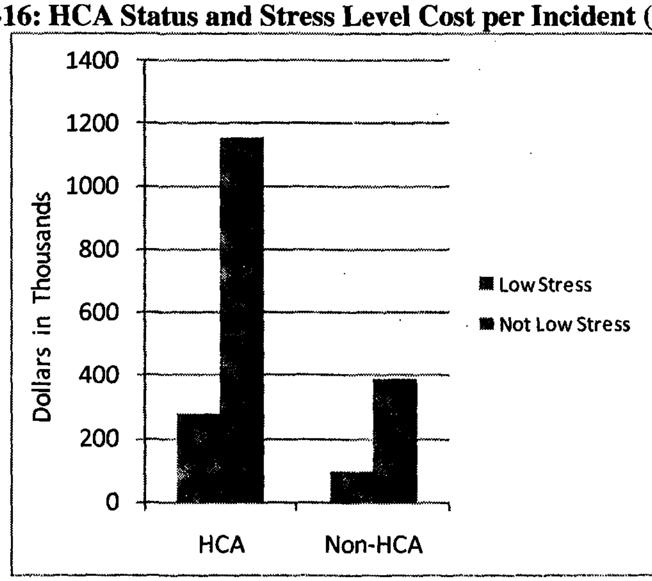
Exhibit 4-15: Net BBL Lost by SMYS (2002-2008)



HCA Status

High consequence areas encompass USAs, navigable waterways, and populated areas. While one cannot treat an incident that occurred in an HCA as if it occurred in an USA, information can be gleaned about USA incidents because the two are related. Exhibit 4-16 shows the per incident cost for HCA and non-HCA incidents by stress level. Within stress level, HCA incidents tend to be more costly. This is likely because spills in high consequence areas require more resources to clean up, and all else equal, the damage associated with a spill in a highly populated area is greater than a spill in a rural field. Within HCAs, not low stress incidents are more costly than low stress incidents. This supports Exhibits 4-12 and 4-14, which show the higher per incident cost of not low stress incidents.

Exhibit 4-16: HCA Status and Stress Level Cost per Incident (2002-2008)



As explained in the section *Per Mile Limitations*, the data in the Annual Report for mileage is distributed marginally. Therefore, a cost per mile analysis of low stress and not low stress incidents by HCA status cannot be conducted. Rather, a number of incidents per mile and cost per mile analysis by HCA status is conducted (See Exhibits 4-17 and 4-18). Data on 1,113 non-HVL onshore incidents is used for this analysis because stress level is not included. There are approximately four more incidents per thousand miles that occur outside of HCAs, as seen in Exhibit 4-17: HCA and Non-HCA Incidents per Thousand Miles (2002-2008). This explains why the cost outside of HCAs is $320 per mile greater than within HCAs.

Exhibit 4-17: HCA and Non-HCA Incidents per Thousand Miles (2002-2008)

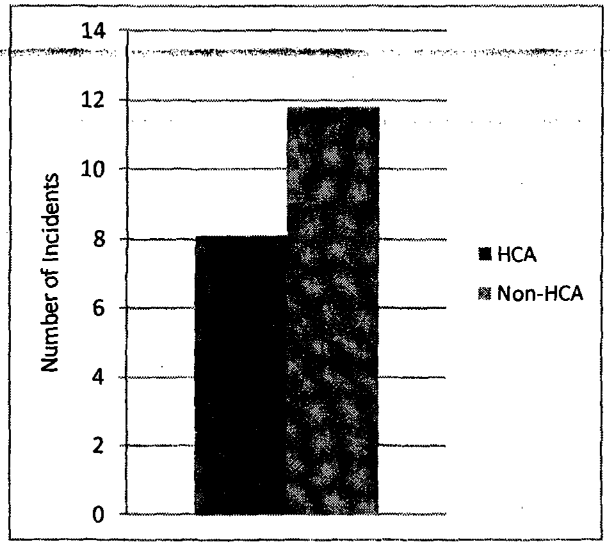
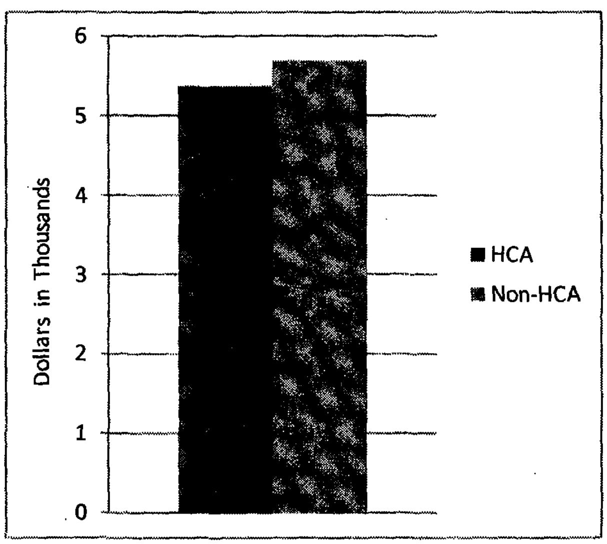


Exhibit 4-18: HCA and Non-HCA Cost per Mile (in Thousands) (2002-2008)



Exhibits 4-16, 4-17 and 4-18 show that while per incident cost is higher within HCAs, 60 percent more incidents occur outside of HCAs than within HCAs.

Low Stress by Cause of Incident

The following is an analysis of the causes of the 117 low stress incidents reported from 2002-2008. Exhibit 4-19 shows the total number of incidents over the seven-year time period. Corrosion is by far the leading cause of incidents at 61, and internal corrosion is 50 percent greater than external corrosion.

Exhibit 4-19: Low Stress Total Incidents by Cause (2002-2008)

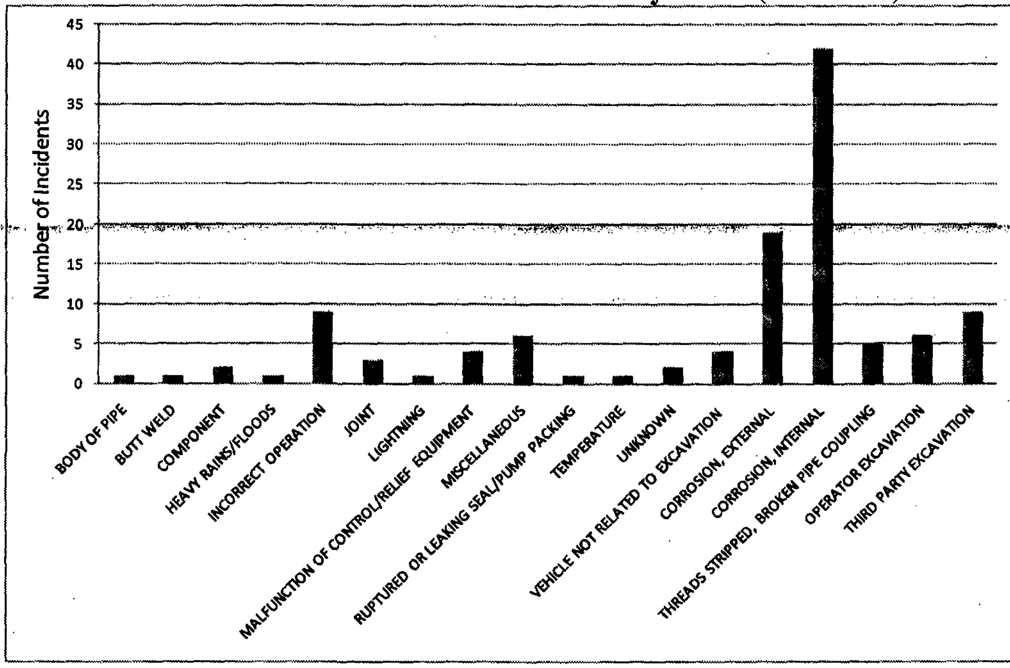
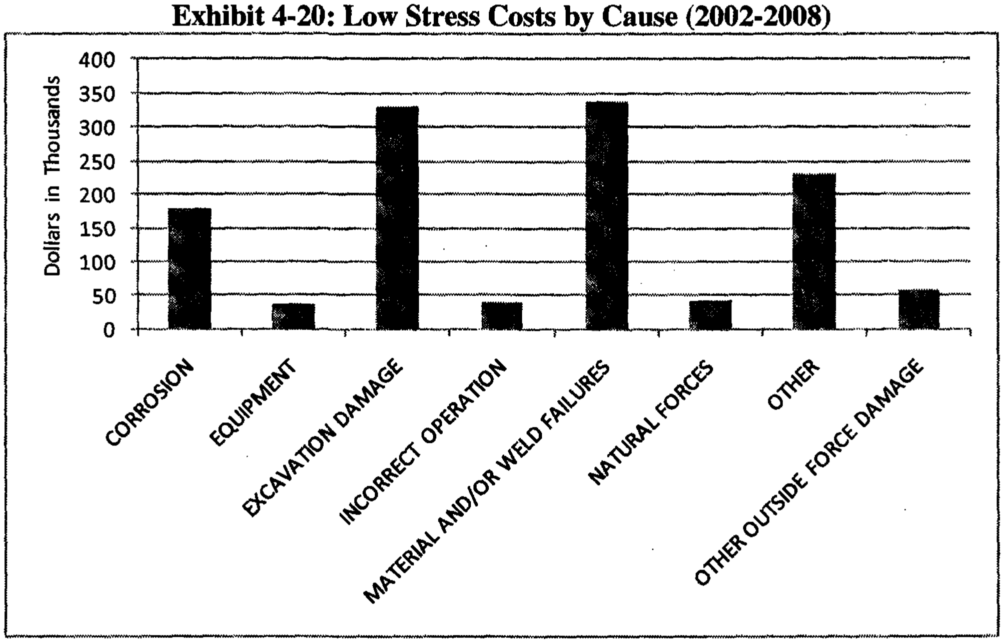


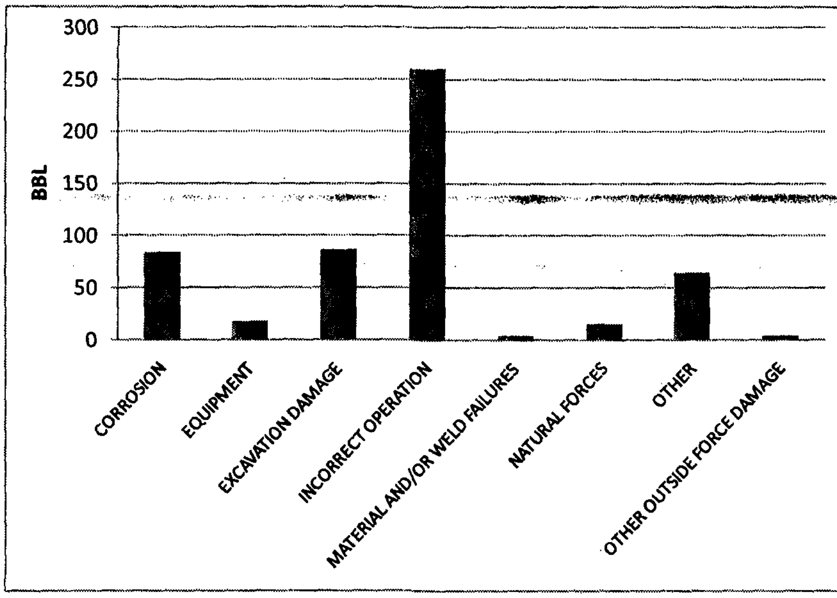
Exhibit 4-20 shows the per incident cost by cause. To correct for outliers, the causes are grouped into eight general categories. For example, when looking at all 25 causes, body of pipe has the highest cost per incident at over $1 million. However, only one of the 117 low stress incidents was due to body of pipe. Excavation damage and material and/or weld failures are the leading causes for cost per incident at near $350,000.

Exhibit 4-20: Low Stress Costs by Cause (2002-2008)



Data on net loss in bbl per low stress incident shows the leading cause is incorrect operation.

Exhibit 4-21: Net BBL Lost by Cause (2002-2008)



Ten Worst Low Stress Incidents

Exhibit 4-22 lists the ten worst low stress incidents in terms of costs in dollars. Three out of 10 are due to corrosion, and they are all in the top four most costly incidents. Six out of 10 occurred in HCAs, which shows costs are not necessarily correlated with the location of the accident. However, the three most costly incidents occurred in an HCA. An examination of pipe size shows that four out of the 10 most costly incidents occurred on pipelines of 8 ⅝" or less. The average cost of these incidents was $1.2 million, the average product lost was 637 bbl and the average net product lost was 128 bbl. The three bolded incidents in Exhibit 4-22 are those that overlap with the ten worst incidents in terms of net bbl lost, which can are seen in Exhibit 4-23.

Exhibit 4-22: Ten Worst Low Stress Incidents by Cost (2002-2008)

Year	Total Cost	BBL Loss	BBL Net Loss	Pipe Size	Cause	HCA
2004	**$2,348,340**	**1,190**	**642**	**12.750**	**External Corrosion**	**Yes**
2004	**$1,560,000**	**709**	**229**	**10.750**	**Third Party Excavation**	**Yes**
2003	**$1,390,073**	**725**	**240**	**2.375**	**Internal Corrosion**	**Yes**
2004	$1,342,721	25	25	20.000	Internal Corrosion	No
2004	$1,054,755	1	0	28.000	Body Of Pipe	Yes
2007	$1,000,000	1,372	0	6.625	Unknown	No
2005	$975,500	991	41	2.375	Operator Excavation	Yes
2003	$972,307	345	100	10.750	Third Party Excavation	No
2003	$790,000	1,000	0	12.750	Miscellaneous	Yes
2007	$660,259	11	0	8.625	Miscellaneous	No
Total	$12,093,955	6,369	1,277			
Average	$1,209,396	637	128			

Exhibit 4-23 lists the ten worst low stress incidents from 2002-2008 by net bbl lost, which can be used as a proxy for environmental damages. Six of the 10 incidents were caused by corrosion, four of which were internal corrosion. Of the top three incidents, two were caused by internal corrosion. Six incidents occurred in HCAs, and four occurred on pipelines with a diameter of 8 ⅝" or less. The average net bbl loss for the ten worst incidents was 829 bbl, the average bbl spilled was 3,100 bbl, and the average total cost was roughly $700,000. The three bolded incidents are those that overlap with the Exhibit 4-22 showing the ten worst incidents in terms of costs.

Exhibit 4-23: Ten Worst Low Stress Incidents by Net BBL Lost (2002-2008)

Year	BBL Net Loss	BBL Loss	Total Cost	Pipe size	Cause	HCA
2006	2,527	3,225	$346,050	8.625	Internal Corrosion	Yes
2005	2,262	7,562	$290,420	12.75	Incorrect Operation	No
2005	688	1,038	$95,381	20	Internal Corrosion	No
2008	652	751	$222,245	0.75	Operator Excavation	Yes
2004	**642**	**1,190**	**$2,348,340**	**12.75**	**External Corrosion**	**Yes**
2006	500	15,000	$120,000	10.75	Miscellaneous	No
2006	333	500	$183,000	12.75	Internal Corrosion	No
2003	**240**	**725**	**$1,390,073**	**2.375**	**Internal Corrosion**	**Yes**
2004	**229**	**709**	**$1,560,000**	**10.75**	**Third Party Excavation**	**Yes**
2006	220	300	$333,194	8.625	External Corrosion	Yes
Total	8,293	31,000	$6,888,703			
Average	829	3,100	$688,870			

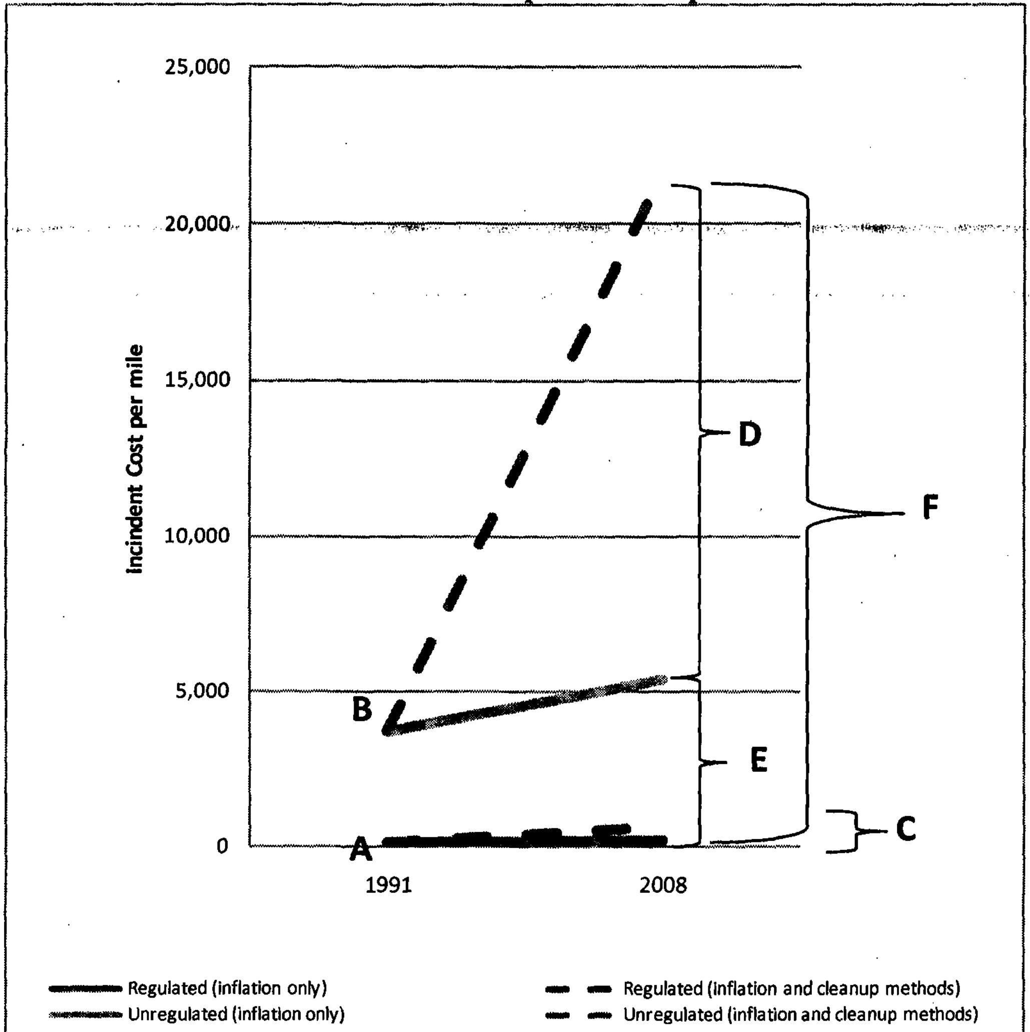
Analysis II: Combination of ANPRM and 7000-1

A primary limitation of the ANPRM method described in the "Data from the 1990 ANPRM / Low stress Phase I" section above, is that the data is twenty years old. Updating the cost estimates from the ANPRM will not encompass all the changes that have occurred since that time in pipeline systems – environmental remediation techniques and the regulatory environment have changed significantly. The following analysis compares the per mile costs for currently regulated lines – $615, as derived from the PHMSA 7000-1 Accident Report database and stated in Analysis I in the section above – to the Phase I inflation-updated costs for ANPRM regulated lines – $153. The difference in the figures, $462 (Gap C in Exhibit 4-24), provides an estimate of the increases in costs beyond inflation.

Expressed as a factor, the $615 current incident cost is 4.02 times above the $153 inflation-updated incident cost. Applying this factor to the ANPRM inflation-updated unregulated cost per mile creates an estimate for current unregulated costs. The application of this factor to the Phase II inflation-updated cost per mile of unregulated low stress pipelines, $5,391 in Exhibit 4-25, results in total unregulated incident cost of $21,670 ($5,391 x 4.02, also provided in Exhibit 4-25). Graphically, the difference in inflation-updated unregulated cost and inflation and methods-updated unregulated cost is provided by Gap D in Exhibit 4-24.

The benefit when only updating for inflation is represented by Gap E in Exhibit 4-24, or $5,238 in Exhibit 4-25. The benefit when updating for inflation and for changes in cleanup practices is represented by Gap F in Exhibit 3-16, or $21,055 in Exhibit 4-25.

Exhibit 4-24: Inflation and Cleanup Method Improvements – Chart



A	Regulated incident cost in 1991 (ANPRM)
B	Unregulated incident cost in 1991 (ANPRM)
C	Additional regulated incident cost due to improved cleanup methods
D	Additional unregulated incident cost due to improved cleanup methods
E	Benefit from regulation (updating for inflation only)
F	Benefit from regulation (updating for inflation and improved cleanup methods)

Exhibit 4-25: Inflation and Cleanup Method Improvements – Table

Type of Estimate	1991 $	2008 $
Cost per mile per year **not in** compliance (inflation only)	$3,692	$5,391
Cost per mile per year **not in** compliance (inflation and practices)	$3,692	$21,670
Cost per mile per year **in** compliance (inflation only)	$105	$153
Cost per mile per year **in** compliance (inflation and practices)	$105	$615
Benefit per mile per year (inflation only)	$3,587	$5,238
Benefit per mile per year (inflation and practices)	$3,587	$21,055

4.3 Collect Data from Individual States

Method

This section describes the various attempts that were made to acquire state data on low stress hazardous liquid pipelines. While this data might serve as a supplement to PHMSA's national database on incidents and miles, not enough information is available to date.

First, the results of the 2009 Volpe follow-up survey to the 2008 Volpe "Rural Low Stress Hazardous Liquid Pipelines Survey" are discussed. Second, attempts to elicit pipeline statistics from California, Texas, Kansas, Oklahoma and Louisiana are discussed.

Volpe Follow-Up Survey

In March 2009, Volpe administered a "Low Stress Pipeline Survey State and Company Follow-Up" survey intended to discern whether there was any additional information on unregulated, low stress hazardous liquid pipelines reported in the original survey. The survey was given to the nine companies reporting the most low stress pipeline mileage in the initial survey, as well as state pipeline regulatory agencies in those nine states. The following information was requested:

- Incident information for the low stress pipeline
- Rate at which reported low stress pipeline are voluntarily operated in accordance with Part 195
- Cost data for complying with portions of Part 195
- Additional information useful in considering the benefit/cost of extending PHMSA's regulatory coverage to the low stress pipeline

Summary of State Regulatory Agency Results

The follow-up survey in the nine states was conducted via phone-interviews and seven out of the nine potential contacts responded and provided information. [24] Five of the seven responding state agencies did not have any incident information on low stress pipeline. [25]

Alaska and Oklahoma indicated that they may have information on low stress pipeline incidents. However, the Alaska Joint Pipeline Office (JPO) stated that to provide the requested information, it would need to have the specific pipelines reported in the survey to be explicitly identified, since there is no other way to separate jurisdictional information from non-jurisdictional information. Furthermore, while the Oklahoma Public Utility Commission noted its responsibility to respond and clean up any incident, whether on regulated or unregulated lines, it also indicated that staff would need to manually go through each incident filing and read what type of pipeline was involved.

Conclusively, both the Alaska Joint Pipeline Office and the Oklahoma Public Utility Commission stated that breaking these data apart from other incident data would require a prohibitively labor-intensive effort.

Further State Follow-up

California, Texas, Kansas, Oklahoma, and Louisiana were contacted in an attempt to gather low stress mileage and incident data on a state level. The following low stress hazardous liquid pipeline data was requested of each state:

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[24] These nine states are: Texas, Michigan, Montana, New Mexico, N. Dakota, Alaska, Ohio, Oklahoma and California

[25] These five states are: Michigan, Montana, New Mexico, N. Dakota and California

- Mileage
- Nominal pipe size
- Incidents
    - Year
    - Cause
    - Costs (product lost, cleanup, property damage, and any other)
    - Amount spilled, amount recovered, net loss (in bbl)
- Whether regulated/unregulated

California

Bob Gorham, Division Chief of the Pipeline Safety Division of the California Office of the State Fire Marshal, provided rural and non-rural low stress mileage data for California. There are 9.09 miles of active low stress rural pipeline and 14.46 miles of active low stress non-rural pipeline. All low stress refined product pipelines have been regulated since 1990. A total of 5.17 miles of the low stress rural pipeline has been regulated since July 2008, and 3.92 miles are currently unregulated. Unfortunately, California provides no incident data on regulated or unregulated low stress lines.

Texas

Gwen Jerrells, Open Records Request Manager of the Pipeline Safety Division for the Texas Railroad Commission, stated that the requested low stress data is currently being gathered, and there is no estimated date of its availability.

A combined effort was made by PHMSA and JFA to contact Mary McDaniels, the Director of the Pipeline Safety Division, but no response was made.

Oklahoma

Craig Weber, Pipeline Program Manager of CleritasWorks and the Oklahoma Pipeline Association, responded that any and all data is only available to the specific pipeline operator that provided it.

Kansas

Leo Haynos, Chief of Gas Operations and Pipeline Safety of the Kansas Corporation Commission, stated that the problems and limitations are as follows: each state has relatively few miles and given low rate of incidence, it may be difficult to develop meaningful data.

Louisiana

James Mergist, Chief of the Pipeline Division Louisiana Department of Natural Resources Office of Conservation, responded that Louisiana does not have the specificity requested for low stress pipelines, and additionally that they do not collect information on non-jurisdictional pipelines.

Lack of Available Data

Despite different approaches taken to collect intrastate low stress data, not enough information is available for a useful analysis. Both survey initiatives ran into the same issue, which is that states are either not willing to share pipeline data or the requested specificity is not available.

4.4 Research and Acquire Data from Other Countries

Description

There is currently little data available on unregulated pipelines in the United States. Research on data pertaining to unregulated pipelines in other countries may provide greater insight on the benefits of regulating unregulated pipelines. However, the vast pipeline network of the U.S. makes it unique. The process is complicated further since countries with little regulation are unlikely to collect incident data. No data on unregulated pipelines in other countries is currently available. However, some international data on incident, injury and fatality rates has been identified and summarized in Exhibit 4-26. This data stems from countries that operate their lines under similar regulations to the U.S. The following sections for each country elaborate on the data summarized in Exhibit 4-26 and provide additional information.

Exhibit 4-26: Pipeline Incident Data (Incident Rate per 1,000 Miles Per Year)

Country	Incidents	Barrels Spilled	Injuries	Fatalities	Overall Failure Rate
Australia Gas (1971-1995)	0.44		0.10		0.08
Europe Haz. Liq. (1981-1994)	0.85	3,822	0.06	0.018	0.61
Japan Gas (1995-2000)	0.49		0.05		
Russia Oil (1990-1996)		7,311			
United Kingdom Oil (1977-2006)	0.36				
United States Haz. Liq. (2002-2008)	1.43	2,123	0.03	0.012	

Australia

The Australian and New Zealand POG database includes data for 8,340 miles of gas pipeline between 1971 and 1995 (208,800 miles-years).[26] No fatalities were recorded in the last 30 years. An incident rate of 0.44 incidents per 1,000 miles per year was reported. The injury rate was 0.103 injuries per 1,000 miles per year.

Europe

The data for the hazardous liquid pipeline incidents in Western Europe are computed from the 1981 through 1994 annual reports presented in the CONCAWE Statistical Summary of Reported Spillages of Oil Industry Cross Country Pipelines in Western Europe.[27] The criteria for including hazardous liquid pipeline incidents in these reports are: all spills greater than one cubic meter (approx. 6 barrels) and spills less than one cubic meter, if the spill had a noteworthy impact on the environment. Only onshore pipelines were included in these data. The incident rate was 0.85 per 1,000 miles per year. The total number of barrels spilled per 1,000 miles-year is 3,822. This reporting criterion does not include any consideration for incidents which cause injury and/or fatalities. As a result, the injury and fatality incident rates of 0.06 and 0.018 per 1,000 miles-year derived from this data may be low.

[26] Data provided by the Office of Gas Safety.
[27] CONCAWE Oil Pipelines Management Group's Special Task Force on Pipeline Spillages (OP/STF-1). Performance of Oil Industry Cross Country Pipelines in Western Europe, Statistical summary of Reported Spillages. 1981 to 1994 annual reports.

Japan

The incident data was sourced for the Japanese transmission and distribution networks between 1995 and 2000.[28] Information of the pipeline length was obtained from the Japan Gas Association website.[29] Furthermore, it is important to note that 84 percent of Japanese gas pipelines are low pressure. The incident rate is 0.49 per 1,000 miles per year and the injury rate is 0.05 per 1,000 miles per year.

United Kingdom

The average incident rate per 1,000 miles per year from1977 to 2006 in the United Kingdom (UK) is 0.36. This information was calculated from data provided by the UK Onshore Pipeline Operators' Association (UKOPA).[30] Furthermore, the failure frequency over the five years 2002-2006 is 0.046 incidents per 1,000 miles per year as compared to 0.42 incidents per 1,000 miles per year during the period 1962-2006.

Russia

During the period between 1970 and 1988 there were 1,426 incidents on gas pipelines in Russia. In 86 incidents there were injuries or fatalities, totaling 275 injuries and 73 fatalities.[31] The average reported amount spilled per 1,000 km-year for FSU (Friends of the Soviet Union) in the years 1990 to 1996 was estimated to be 618 metric tons as compared to an average of 323 metric tons in Western Europe from 1971-1993.[32] This can be converted to a total of 7,311 barrels per 1,000 miles per year spilled in the FSU. This number is about three times greater than the number of barrels spilled in the U.S. and in Europe. Although it is likely that this figure is underestimated, it is clear that the amounts spilled per ton transported in FSU are higher than in Western Europe.

United States

The 7000-1 data yields an incident rate of 1.4 per 1,000-miles-year and an injury rate of 0.03 per 1,000 miles-year for all pipelines. The fatality rate per 1,000 miles per year is 0.012 for all pipelines. Compared to the international data, the U.S. has an above average incident rate but lies below the average regarding injury and fatality rates internationally. The total number of barrels spilled per 1,000 miles per year is 2,123, a number lower than in both Europe and Russia.

Conclusion

Conclusions on incident statistics for international pipelines cannot be drawn with complete certainty due to differences in regulations and types of commodities transported. However, data for countries with relatively high incident statistics can be roughly compared to what an unregulated pipeline system might look like. In regards to injury and fatality rates, the U.S. lies below the international average; half as many injuries occur per 1,000 miles per year in the U.S. than in Europe and one third fewer fatalities occur in the US than in Europe on a per 1,000 mile per year basis. In regards to barrels spilled, one study showed that the number of barrels spilled per 1,000 miles per year in Russia is three times the number of barrels spilled in Western Europe and the United States. Among other factors, the difference in total spillage can be attributed to differences in regulation. Countries with regulations similar to the U.S. seem

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[28] Japan Agency for Natural Resources and Energy, Agency for Nuclear and Industrial Safety
[29] http://www.gas.or.jp/gasfacts_e/4/index.html
[30] UKOPA Pipeline Fault Database
[31] Risk and Reliability Associates Pty Ltd. Overseas and Australian Statistics for Gas Transmission and Distribution Incidents. January 2004.
[32] World Bank Energy Sector Management Assistance Programme (ESMAP)

to have fewer barrels spilled per 1,000 miles. One limitation is that there is no data available on unregulated incidents internationally at this point in time. However, the sources of incident data for foreign countries can be used to examine corrosion and excavation damage frequencies in unregulated environments in future studies.

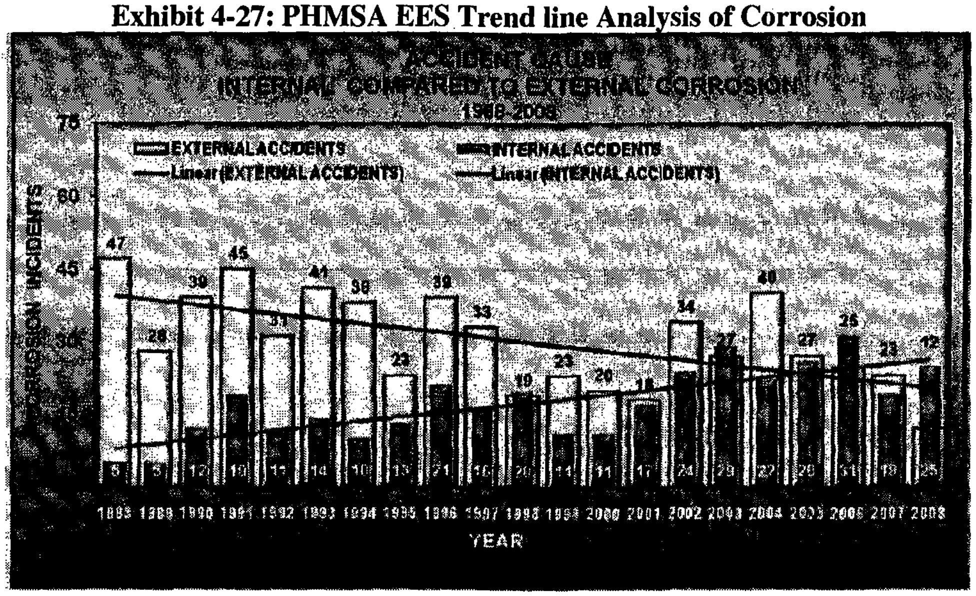
4.5 Time Series Incident-Cause Trend Line Analysis

Method

Trend estimation of time series data is a statistical technique to aid interpretation of data. When a series of measurements of a process are treated as a time series, then the application of trend estimation can be used to make and justify statements about trends in the data. In particular, it may be useful to determine if measurements exhibit an increasing or decreasing trend which is statistically distinguished from random behavior.

Analyzing time series data on rates for specific types of pipeline failures, such as corrosion, excavation, etc., is a common approach in pipeline regulatory analysis. For example, Joshua Johnson, a metallurgical engineer for the Engineering and Emergency Support Office of Pipeline Safety, developed a presentation on corrosion for an internal corrosion workshop (see Exhibit 4-27).[33] The analysis examined trend lines of internal and external corrosion rates over time.

Exhibit 4-27: PHMSA EES Trend line Analysis of Corrosion



Another example of this approach is Exhibit 4-28, a time series graph developed by PHMSA.[34] It shows significant pipeline incidents caused by excavation damage on various pipeline systems over time.

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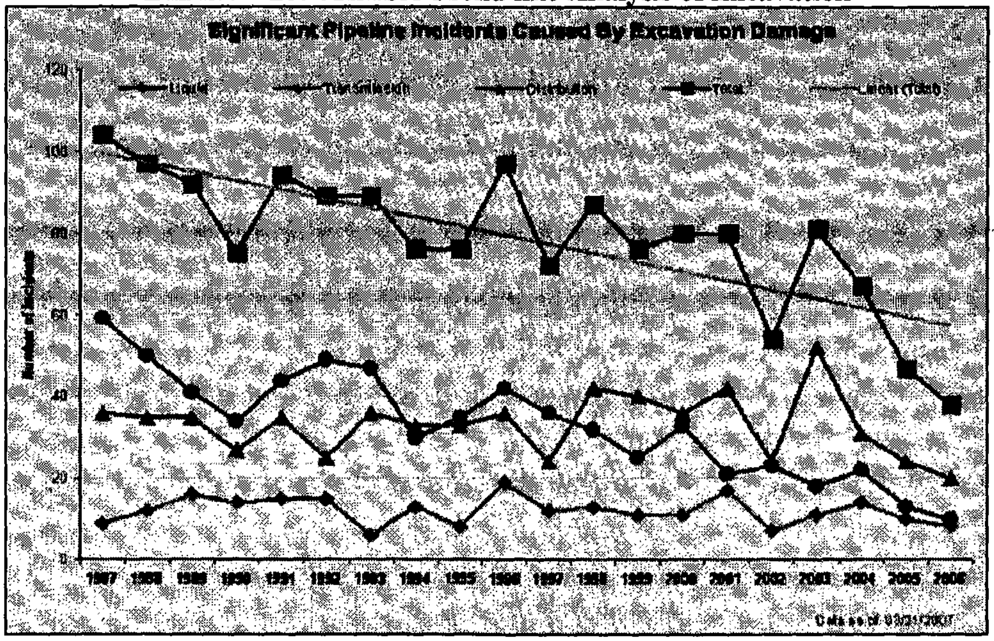
[33] Johnson, Joshua. "Internal Corrosion: PHMSA Data and History." Engineering & Emergency Support, Office of Pipeline Safety. Workshop on Internal Corrosion in Hazardous Liquid Pipelines, Atlanta Georgia World Congress Center, March 29, 2009.

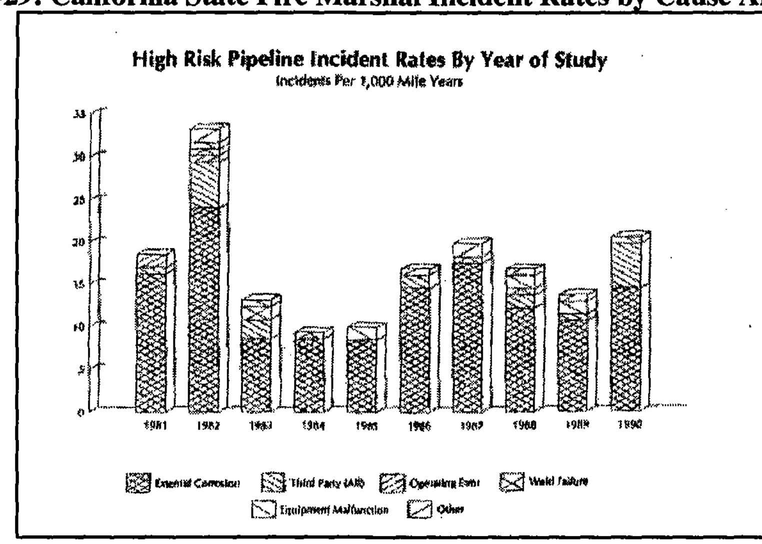
[34] West, John. "Significant Pipeline Incidents Caused by Excavation Damage," slide from PHMSA presentation "Organization and Regulatory Overview" http://www.kcc.state.ks.us/pipeline/2008_seminar/PHMSA_Organization_and_Rule_Update.pdf

Exhibit 4-28: PHMSA Trend line Analysis of Excavation



In a 1993 report produced by EDM Services, Inc. for the California State Fire Marshal, a similar analysis is presented (see Exhibit 4-29).[35] In this example, incident rates for external corrosion, third party damage, and other incident causes are analyzed over a 10-year period.

Exhibit 4-29: California State Fire Marshal Incident Rates by Cause Analysis



To produce a benefit-cost analysis for the regulation of currently unregulated pipelines, one would ideally use a database containing information on incident rates for regulated and unregulated low stress lines over a long period of time. Or barring that, information on incident rates for regulated and unregulated lines over a long period of time might still be useful. Unfortunately, this information is not currently available. However, following the time series approach, one can look at the rate of hazardous liquid pipeline

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[35] "Hazardous Liquid Pipeline Risk Assessment." California State Fire Marshal, conducted by EDM Services, Inc. Page 96. March 1993.

incidents by cause over time. Examining regulated incident rates from 1986 gives an idea of what a substantially, but not completely, regulated line might look like.

Data

For the analysis of incident rates by cause of incident over time, PHMSA's Hazardous Liquid Significant Incidents databases are mined. The first database covers years 1986-2001 and the second covers 2002-2008. These databases are used because they have a consistent reporting threshold over time: only incidents of 50 bbl spilled or more. Although using this threshold decreases the number of incidents reported per year, it allows for an analysis of incidents from 1986-2008. In addition, HVL and offshore incidents are removed because they are not part of the rulemaking.

Causes

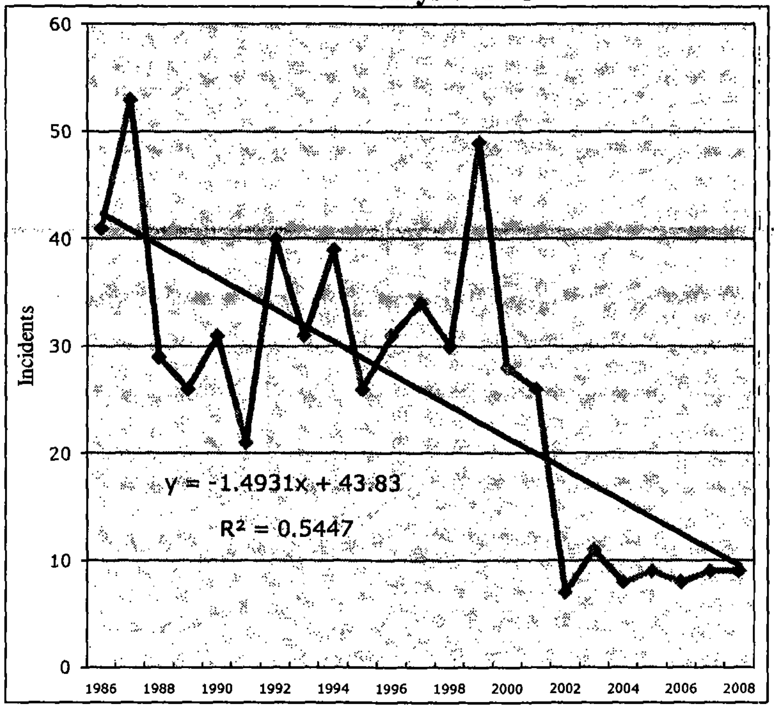
From 2001 to 2002, the list of possible causes goes from 8 to 25. For consistency, the causes from 2002-2008 are grouped into the 8 categories listed from 1986-2001. These eight causes are: external corrosion, internal corrosion, equipment, incorrect operation, material and/or weld failures, natural forces, outside force damage, and other. Excavation is not listed as one of the eight causes. In order to include it, the yearly numbers are extracted from the chart above (Exhibit 4-28). Excavation is a type of outside force damage. The yearly excavation figure is subtracted from outside force damage so as to not double count it. Once excavation is removed from outside force damage, there are very few outside force damage incidents to be analyzed. For this reason, outside force damage is excluded from the following analysis. In addition, natural forces caused incidents are relatively constant over time, with a slight upward slope. While the costs associated with natural force-caused incidents may have declined over time due to regulatory processes, one would expect the number of natural force-caused incidents to stay relatively unchanged. For this reason, natural force incidents are excluded from the following analysis. Adding excavation and removing other outside force damage and natural forces leaves a total of 7 causes.

"Other"

One of these seven cause categories is "other," which indicates the actual cause is not specified. Charting "other" over time, as seen in Exhibit 4-30, there is a significant drop in incidents starting in 2002. The average number of "other" incidents between 1986 and 2001 is 33, with a maximum of 53 in one year and a minimum of 21 in another, whereas the average number of "other" incidents between 2002 and 2008 is 9, with a maximum of 11 one year and a minimum of 8 in another. This is quite likely due to the reporting change and not an actual drop in those types of incidents.

Therefore, a modification to the data is made to distribute the "other" cause across the six remaining causes. Each cause is scaled up to agree with the total costs and number of incidents. An analysis of the remaining six causes is provided in the next section.

Exhibit 4-30: Trend line Analysis of "Other" Incidents



Analysis

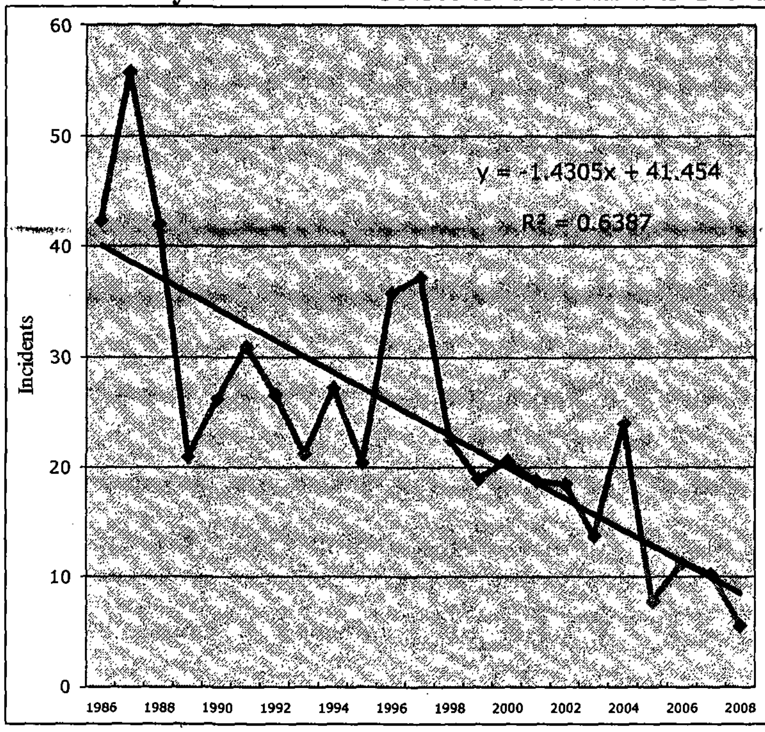
In this section, each cause is graphed over time and given a trend line. To determine the benefits of regulation, trend line incident rates from 1986 are compared to trend line rates from 2008. The 1986 figure is treated as a rough picture of what incidents rates would have been for that cause on unregulated lines. The 2008 figure is what incident rates might look like on regulated lines. Dividing the 1986 rate by the 2008 rate gives an "unregulated factor," which is then multiplied by current average incident costs per mile[36] to get past average incident costs per mile. In other words, a proxy is used for the cost per mile of regulated and unregulated incidents by cause. The difference in these two figures is treated as the benefits of regulation.

External Corrosion

Exhibit 4-31 shows incident rates for external corrosion over time, along with a trend line and the formula for the trend line. It appears external corrosion has decreased roughly 75 percent over time. To determine the beginning and end points of the trend line, the y-intercept 41.5 is used as the 1986 figure, and solving the trend line equation gives a 2008 figure of roughly 10. This gives an "unregulated factor" of 4.2. Multiplying this factor by the inflation-updated average annual cost per mile from 2002-2008 for external corrosion, $101, gives an unregulated cost per mile of $419. The difference between this figure and the regulated cost per mile is the per mile benefit from regulation for external corrosion, which is **$318**.

[36] Costs used are the 2002-2008 incident costs updated for inflation to 2009 dollars using the Bureau of Economic Analysis Implicit Price Deflator for GDP. Miles used are the 111,000 hazardous liquid onshore non-HVL miles reported on the 2008 Annual Report.

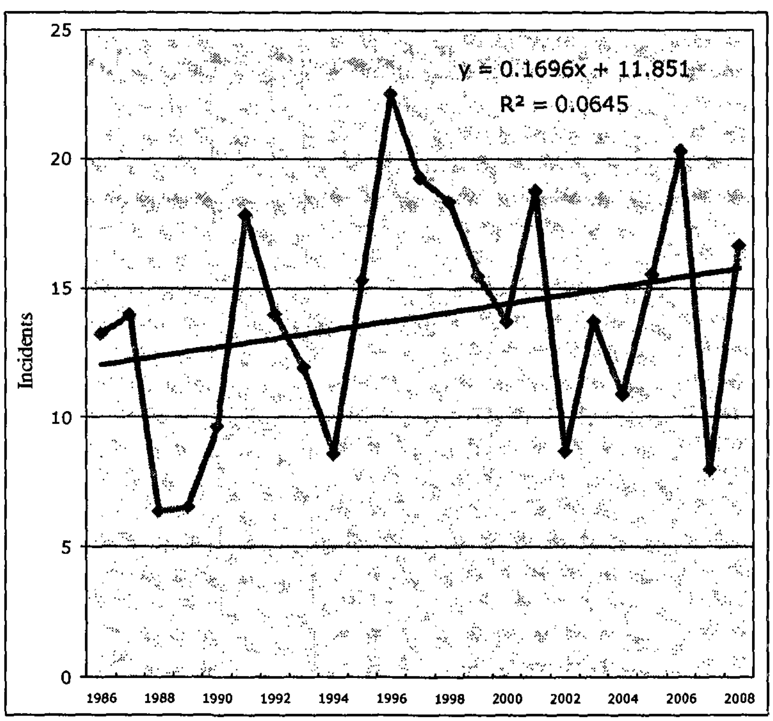
Exhibit 4-31: Analysis of External Corrosion Incidents with Trend Line



Internal Corrosion

Exhibit 4-32 shows that over the entire 23 year period, overall incident rates for internal corrosion increased.

Exhibit 4-32: Analysis of Internal Corrosion Incidents (1986-2008) with Trend Line



Internal corrosion was a growing problem, but procedures put in place by regulatory agencies and pipeline operators, for example the Integrity Management Program (IMP), have appeared to change the trend. For example, a trend line analysis of the time period 1996-2008, Exhibit 4-33, shows a decrease in the number of incidents per year. A trend line analysis from 1986-1996 and extrapolated to 2008, Exhibit 4-34, shows an increase. One can attribute these different slopes at least partly to regulatory oversight.

Exhibit 4-33: Analysis of Internal Corrosion Incidents (1996-2008) with Trend Line

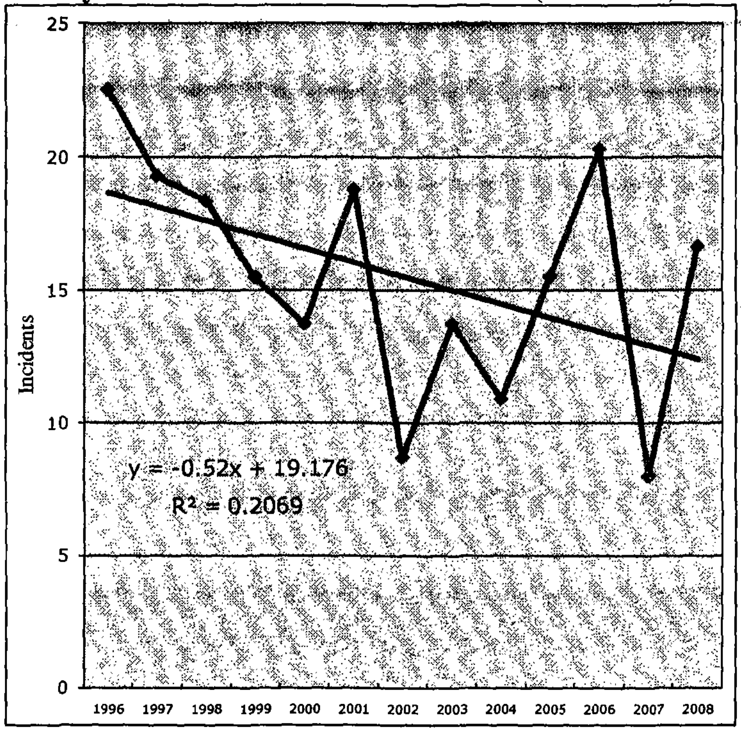
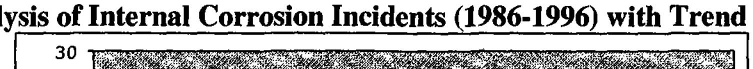


Exhibit 4-34: Analysis of Internal Corrosion Incidents (1986-1996) with Trend Line, Extrapolated

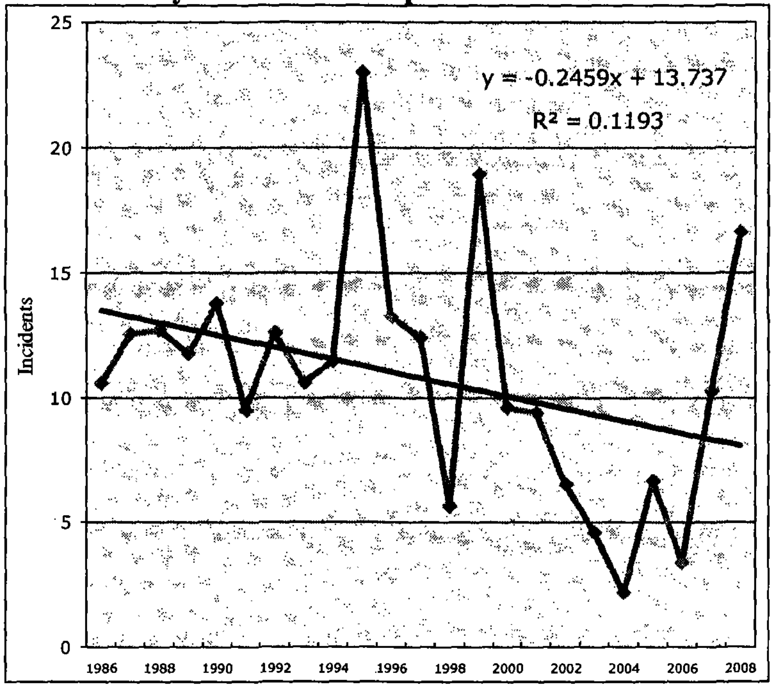


The 2008 point on the 1996-2008 trend line seen in Exhibit 4-33, is an example of what incident rates on a regulated line might look like. The average incident rate for a regulated line is thus 12.5. For an unregulated line, the trend line for 1986-1996 is used and then extrapolated to 2008. The 2008 point 25.5 is used as the average incident rate for an unregulated line. This point represents what an unregulated incident rate might look like today without the implementation of regulatory procedures. Dividing these incident figures gives an "unregulated factor" of roughly 2. Multiplying this factor by the inflation-updated average annual cost per mile from 2002-2008 for internal corrosion, $27, gives an unregulated cost per mile of $55. The per mile benefit from regulation for internal corrosion is thus **$28**.

Incorrect Operation

Exhibit 4-35 shows incident rates for incorrect operation over time, along with a trend line and the formula for the trend line. It appears incorrect operation has decreased roughly 40 percent over time. The regulated 2008 incident point is 8.3 and the unregulated 1986 point is 13.7. The "unregulated factor" is 1.6. Multiplied by the inflation-updated average annual cost per mile from 2002-2008 for incorrect operation, $13, the resulting unregulated cost per mile is $21. The benefit from regulation, therefore, is **$8** per mile.

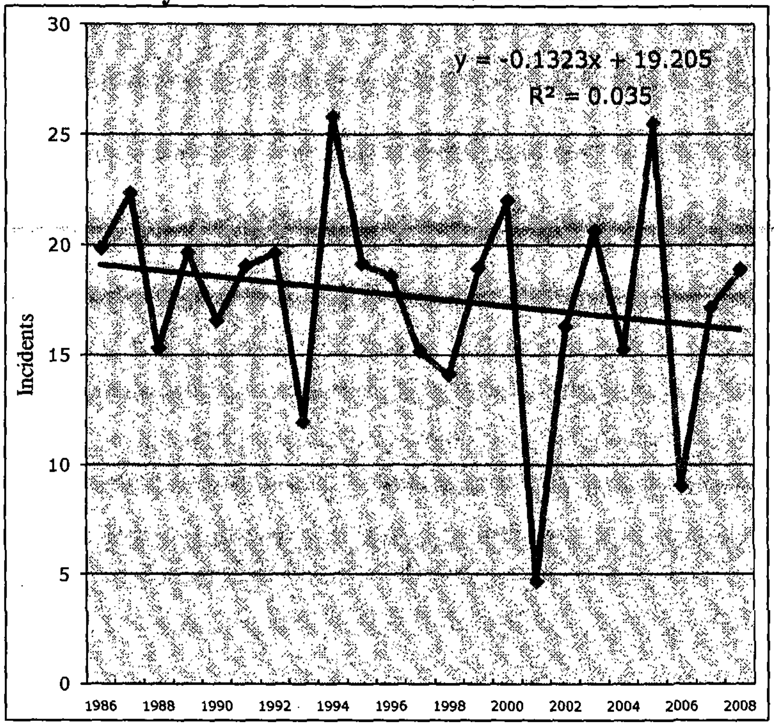
Exhibit 4-35: Analysis of Incorrect Operation Incidents with Trend line



Material and/or Weld Failure

Exhibit 4-36 shows that incident rates for material and/or weld failure have decreased roughly 15 percent over time. The regulated 2008 incident point is 16.3 and the unregulated 1986 point is 19.2. The "unregulated factor" is 1.2. Multiplied by the inflation-updated average annual cost per mile from 2002-2008 for incorrect operation, $189, the resulting unregulated cost per mile is $223. The benefit from regulation, therefore, is **$34** per mile.

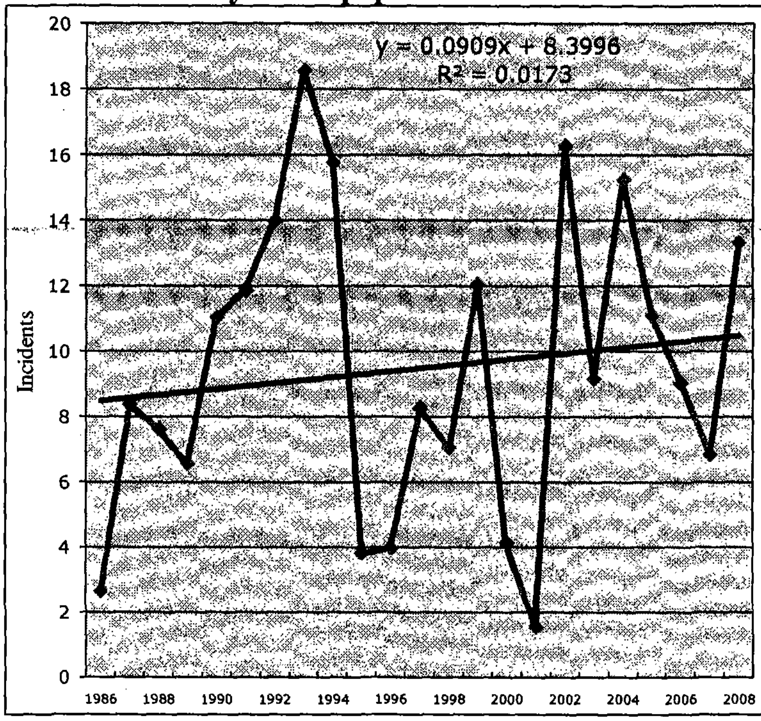
Exhibit 4-36: Analysis of Material and/or Weld Incidents with Trend line



Equipment

A trend line analysis of equipment-caused incidents over time shows a small upward slope of .09, as shown in Exhibit 4-37. However, it is likely there was an increase in the amount of equipment per mile from 1986 to 2008. All else equal, more equipment entails a higher probability of equipment-caused incidents. Assuming that equipment has increased close to 50 percent over time, the 1986 trendline point is then multiplied by 1.5. The unregulated 1986 point is thus 12.6 and the regulated 2008 point is 10.4. The "unregulated factor" is 1.2. Multiplied by the inflation-updated average annual cost per mile from 2002-2008 for equipment, $19, the resulting unregulated cost per mile is $23. The benefit from regulation, therefore, is **$4** per mile.

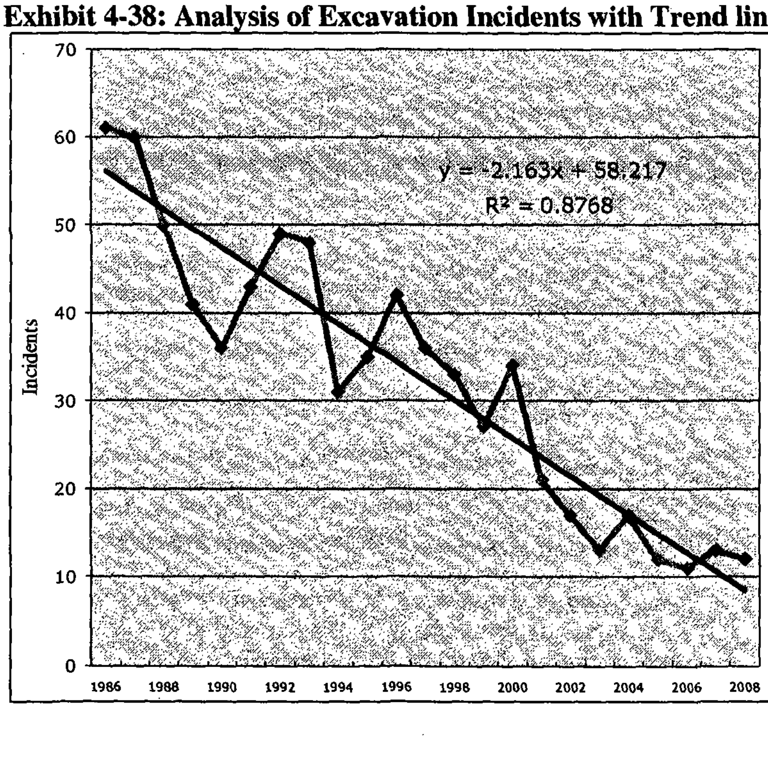
Exhibit 4-37: Analysis of Equipment Incidents with Trend line



Excavation

Exhibit 4-38 shows that incident rates for excavation have decreased roughly 80 percent over time. The regulated 2008 incident point is 10.6 and the unregulated 1986 point is 58.2. The "unregulated factor" is 5.5. Multiplied by the inflation-updated average annual cost per mile from 2002-2008 for incorrect operation, $63, the resulting unregulated cost per mile is $345. The benefit from regulation, therefore, is **$282** per mile.

Exhibit 4-38: Analysis of Excavation Incidents with Trend line



Total Benefit

To determine the benefits of regulation, the analysis compared changes in incident rates from 1986 to 2008. The 1986 rates (presented graphically as the left end point of each trendline in Exhibits 4-31 to 4-38 and numerically in the third column of Exhibit 4-39) provide a rough picture of what incidents rates would have been for that cause on a substantially regulated line. The 2008 figure (presented graphically as the right end point of each trendline in Exhibits 4-31 to 4-38 and numerically in the second column of Exhibit 4-39) is what incident rates might look like on a current and fully regulated line. Dividing the 1986 rate by the 2008 rate gives a "substantially regulated factor" (the fourth column in Exhibit 4-39) which is then multiplied by current average incident costs per mile (the fifth column in Exhibit 4-39) to get an idea of the average incident costs per mile in 1986 (the sixth column in Exhibit 4-39).[37] Again, these estimated average incident costs per mile from regulated lines in 1986 are an idea of what a substantially regulated line might look like today. The difference in these two figures provides a proxy of the benefit of bringing a substantially regulated line into full compliance (the final column in Exhibit 4-39).

The benefit estimates for each incident type are provided in the final column of Exhibit 4-39, and are then summed to determine the total benefit from bringing a substantially regulated line into full compliance. This estimate is $674 per mile.

Exhibit 4-39: Cause Incidents Per Mile, Cost Per Mile, and Sum of Benefits

	Regulated Incident Rate per mile	"Unregulated:" Incident Rate per mile	"Unregulated Factor"	Regulated Cost per mile	Unregulated Cost per mile	Benefit per mile
External Corrosion	10.0	41.5	4.2	$101	$419	$318
Internal Corrosion	12.5	25.4	2.0	$27	$55	$28
Incorrect Operation	8.3	13.7	1.6	$13	$21	$8
Material and/or Weld Failure	16.3	19.2	1.2	$189	$223	$34
Equipment	10.4	12.6	1.2	$19	$23	$4
Excavation	10.6	58.2	5.5	$63	$345	$282
Total	68.1	170.6		$412	$1,087	**$674**

Exhibits 4-31 to 4-38 provide the R^2 values for the trend lines. These values show the correlation between incident rate and time. The two major incident causes, External Corrosion and Excavation, are also highly correlated with R^2 values of 0.64 (R = 0.80) and 0.88 (R = 0.94), respectively. The estimated benefit per mile of these incident types are also the largest, at $318 and $282, respectively. The R^2 values for the other incident types are not as large and the estimated benefits per mile for each are also quite small. These benefits range from $4 to $34 per mile. If it were assumed there was no benefit to the rates of these incident causes with low trend line R^2 values, the total estimated benefit from bringing a substantially regulated line into full compliance would be $600. This $74 difference has a nominal effect on the final benefit estimates of bringing an unregulated line into compliance, and, therefore, the remainder of the analysis uses the $674 benefit estimate for bringing a pipeline already substantially in compliance into full compliance.

[37] Costs used are the 2002-2008 incident costs updated for inflation to 2009 dollars using the Bureau of Economic Analysis Implicit Price Deflator for GDP. Miles used are the 111,000 hazardous liquid onshore non-HVL miles reported on the 2008 Annual Report.

4.6 Collect Industry Data

Description

Several different initiatives have been undertaken to collect data on the benefits of low stress pipeline regulation. The first initiative consisted of contacting the Pipeline Performance Tracking System (PPTS) to gather tracking info and the second initiative was to contact pipeline companies directly and collect information via e-mail and phone interviews.

PPTS data

PPTS, a repository for data on pipeline incidents, is a joint effort of API and AOPL. It covers data from pipeline companies who operator 85 percent of all pipeline miles. Since 2002, the system can differentiate whether incidents are in or out of an HCA and whether they involved a low stress line. It includes a variety of information including the cause of the incident. There is a possible to tell whether the incident occurred on a regulated or unregulated line and a request has been submitted to API asking for a summary of this data. This information has not been received yet, but a summary of all onshore pipeline incidents collected by the PPTS is summarized in the Exhibits 4-40, 4-41 and 4-42 below.

Exhibit 4-40: (PPTS Example) Liquids Pipeline Industry Onshore Pipe Spill Record[38]

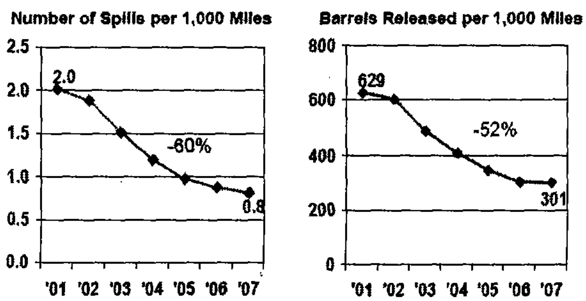
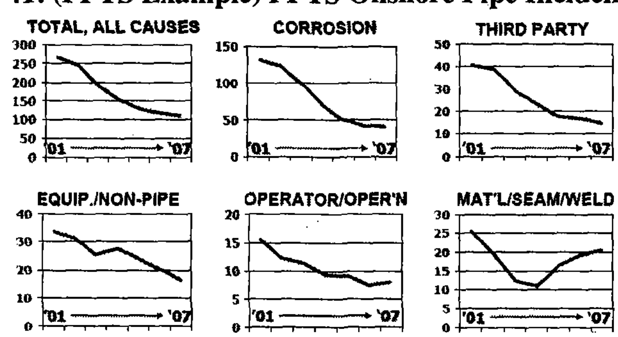


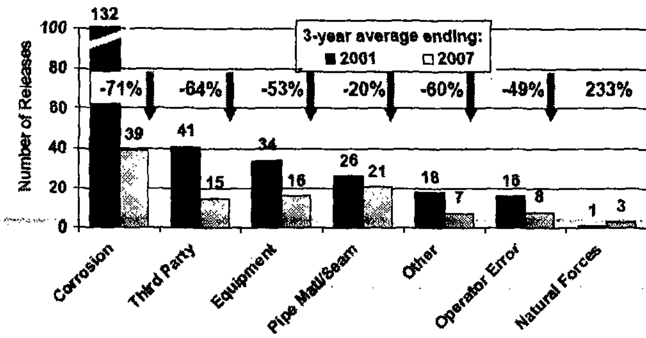
Exhibit 4-41: (PPTS Example) PPTS Onshore Pipe Incidents, '99-'07[39]



[38] PPTS. http://www.api.org/aboutoilgas/sectors/pipeline/upload/PPTS_Short_SlideDeck_2007.pdf. Pipeline Performance Tracking System: a voluntary spill reporting system involving 85 percent of the U.S. liquids pipeline mileage. Percentage decline from 1999-2001 average to 2005-2007 average.

[39] PPTS. http://www.api.org/aboutoilgas/sectors/pipeline/upload/PPTS_Short_SlideDeck_2007.pdf

Exhibit 4-42: (PPTS Example) Reduction in Releases along Right-of-Way[40]



Data Collected Directly from Pipeline Companies

As part of the data review process of the Volpe Survey the study team has contacted several companies to clarify the information provided to Volpe. The qualitative responses provided by the Volpe survey firms are summarized below. Additional comments regarding the regulation of low stress pipelines are summarized in Exhibit 4-43.

Discussion of Qualitative Benefits

The objective of Part 195 regulation for rural, low stress pipelines is to reduce the likelihood of an accident and exposure risk to the public, personnel, property and environment. The benefits vary depending upon past and present operator construction, operations and maintenance practices, the commodity being transported, age and type of pipe, operators experience with existing pipeline systems, and perception of risk and benefit.

Some of the expected benefits of potential regulation that have been collected from interviews with 21 companies are qualitatively discussed below.

Rural Low Stress Pipe Incident Rate

It has been perceived that the accident rate per 1000-mile-years for low stress pipe should be less than pipelines operating at high stress levels. In the California State Fire Marshal study Hazardous Liquid Pipeline Risk Assessment, the median value of such leaks was found to be relatively low at 24 percent and there was not necessarily a correlation between operating pressure and leak accident rates.[41] Although this study only assessed California's regulated pipelines in the 1980s, it is expected that the conclusions would be similar for the Phase II pipelines.

Deliverability and Reliability

Improved deliverability and reliability may be a beneficial outcome of some operator's pipeline systems due to regulation. Training, abnormal operation recognition and monitoring of cathodic protection systems are all programs that may have to be enhanced. As a trade-off, some operators may have to increase capital and maintenance budgets for regulatory compliance. However, the results should extend the life cycle of such systems beyond what was originally intended. Some operators may realize cost savings later due to less frequent disruptions and releases. Also, the potential replacement cost will be higher than the originally installed cost and may not be as achievable.

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[40] PPTS. http://www.api.org/aboutoilgas/sectors/pipeline/upload/PPTS_Short_SlideDeck_2007.pdf
[41] Payne, Brian. Hazardous Liquid Pipeline Risk Assessment, California State Fire Marshal, March 1993.

Since there have been frequent acquisitions and divestitures of pipeline systems, operation and maintenance in accordance with Part 195 may increase the value of the asset in the eyes of the buyer and seller.

Government Pending Regulation

Impending government regulation may motivate operators to reassess operations and maintenance practices and make repairs to pipelines that were not as closely monitored. Such pipelines may have been considered as lower risk due to lower pressures and lack of regulatory oversight; the consequences of a low stress pipeline failure may not have been deemed as great.

Pending regulation has motivated operators to assess those pipelines that may have impacts upon environmental sensitive areas (i.e., USAs) and provided them greater recognition.

Verification and Recordkeeping

Contemporaneous recordkeeping as required by Part 195 demonstrates that the operator is maintaining facilities in accordance with minimum prescribed requirements. Such practices may not have been incorporated by all operators. Pipe maps and pipe records may be lost or never recorded or retained, operations and maintenance surveys may not be as rigorous and frequent as prescribed by Part 195. Some operators do recognize the increased cost and responsibility for maintenance of such records.

Pre-1970 ERW and Unknown Pipe

Pre-1970 low-resistance ERW pipes have been considered problematic. PHMSA has been tracking this type of pipe with the regulated pipeline operators. The pipe has been managed and identified as a risk management item.

Due to lower operating pressures, it is believed that the weld failure rate may be less. PHMSA will be able to continue to track the performance of this pipe for low stress pipelines.

Due to operator practices, records may not have been maintained for installed pipe. Although there may not be any leak history or issues, operators will need to verify the pipe in accordance with Part 195 or be required to curtail maximum operating pressure to 100 psig or less. One respondent to the Volpe survey has acknowledged that there are no records for 3-mile delivery lines not presently affecting an USA.

Leak Reporting

There are existing Federal and State laws for reporting uncontrolled or accidental releases of hazardous materials if the release exceeds a reportable quantity, involve an injury or fatality, or a financial loss. Such releases may be reported to other Federal or State environmental or emergency response agencies or the National Response Center (NRC). However, unregulated pipeline accident records may not be readily available to PHMSA or State pipeline safety agencies for risk management and decision making. For example, considerable database management and analysis of the NRC incident records are required for non-DOT pipelines that could be relevant for Phase II rulemaking evaluation. Operating stress levels of pipelines are not a NRC reporting requirement.

Phase II Low Stress Pipeline NPMS Reporting

Due to the Phase I low stress regulation, certain operators with gathering and low stress pipelines had to determine which pipeline segments were subject to the appropriate categories for regulatory purposes. Certain operators had insufficient mapping records, while others had improved mapping and GIS information. Regulated operators may be submitting additional and better data to the National Pipeline

Mapping System (NPMS) as part of the annual reporting. The additional mapping information should assist local government responders and emergency response agencies where such pipelines are located and provide better uniformity in local planning. Some states and counties already have such requirements and capabilities. The NPMS is not intended to supersede those requirements.

Integrity Management Programs

Operators of Phase II low stress pipelines potentially affecting USAs generally have not been managing their pipelines in accordance with Part 195 integrity management program although some elements may have been adopted as a risk management tool. Such pipelines will need to be assessed similarly to other pipelines. Due to potential configuration and size, it is expected that pressure tests and ECDA methods may increase. Operators may elect to pressure test line segments due to no or recent records of line segments as a baseline assessment. Such tests will lead to waste water treatment and handling issues. States or the USEPA regulate the discharge of such water from operating pipelines as a result of hydro tests that are part of NPDES permit programs.

For 8" and greater Phase II line sections that are part of a line segment containing a Phase I section, greater information on integrity may be obtained if ILI tools are run. Operators should be better informed and be able to make decisions on a risk management basis for the Phase II sections.

Part 195 and ASME B31.4 and Other Industry Practices

Although Part 195 generally follows ASME B31.4 and other recognized practices for design and construction, there are some differences. For example, ASME B31.4 allows leak testing but Part 195 requires pressure (proof) testing.

The use of qualified welders, increased use of non-destructive examinations and inspections may increase depending upon the pipeline sector.
To prove the integrity of pipeline systems, operators may elect pressure test pipeline segments as part of integrity management programs or to establish maximum operating pressure (MOP).

Emergency Response Training

There may be shorter large diameter pipeline segments and smaller diameter pipelines that are required to have Oil Response Plans and become regulated under 49 CFR 195. Since the Volpe respondents had line segments regulated by Part 195, emergency response training was not an issue. For those operators not presently regulated, emergency response training and exercises may become more recognized and frequent in order to mitigate the risk of spills.

Damage Prevention

Most states require pipeline operators to register with state or regional One-Call centers and to locate and mark their lines in response to a One-Call excavation ticket. For those pipeline operators with short segments, the risk is believed to be low because they may be near a facility, where activities can be readily monitored, or in proximity to regulated pipelines. For those operators with longer mileage there is a greater chance of third-party damage, although this activity is believed to be low.

Interviewed operators patrol their unregulated pipelines in accordance with current Part 195 practices. Potentially regulated operators would be required to have personnel on-site when the pipe is exposed and inspect coating as part of Subpart H requirements. These regulated operators would also have to implement appropriate Common Ground Alliance (CGA) best practice guidelines as part of their damage prevention provisions in their Integrity Management Program.

Chemical, Petrochemical, Terminal and Gas Processing Pipelines

Only three chemical, petrochemical, bulk marketing terminals, gas processing organizations that responded are potentially subject to Phase II. Their pipelines are either already being regulated or have other regulated pipelines. They do not consider themselves as part of the pipeline industry community. Each organization generally operates and maintains their pipelines in accordance with recognized practices and Part 195. In addition, one facility, as part of its risk management program, has a pipeline in a pressurized casing for leak detection due to the hazardous nature of the commodity when it is released to the environment.

On October 14, 2009, it was reported to the NRC that a distribution-type, non-DOT pipeline near Geismar, Louisiana leaked 5000 pounds of methyl alcohol between plants due to a pinhole leak. The pipeline is operated by Hexion Specialty Chemicals. It is not listed as a pipeline operator and it is not known whether they were aware of the Volpe survey. Due to lack of a response, the pipeline could either be excluded as an interplant delivery line or potentially regulated as a Phase II low stress pipeline. Because these non-traditional pipeline operators in certain sectors have not previously regulated, the cost-benefit aspect is expected to vary due to various risk management practices. It is expected that additional information could be obtained during the rulemaking decision process. In further announcements, it is recommended that the Independent Liquid Terminal Association, American Chemical Council, Synthetic Chemical Manufacturers Association, The Fertilizer Institute, Gas Processors Association and other potentially interested industrial associations should be notified in the future. The dialogue with such non-pipeline sectors may prove to be useful.

External Corrosion

It is recognized that external corrosion is the leading cause of rural low stress pipelines accidents. Cathodic protection significantly reduces such occurrences. Also the frequency of inspection has been found to lower the accident rate as reported in the California State Fire Marshal study An Assessment of Low-Pressure Crude Oil Pipelines and Gathering Lines.

All pipeline operators either operate their pipelines in accordance with Part 195 or have cathodic protection systems. One crude oil pipeline operator advised that several additional test stations would likely need to be installed and close-interval surveys would determine the adequacy of the cathodic protection system. Also the frequency of inspections would likely have to be increased.
One pipeline operator with an above-ground pipeline does not have a cathodic protection program but has a painting maintenance program for external corrosion control.

Internal Corrosion

Internal corrosion has been historically considered to be the second highest risk. As illustrated at the recent PHMSA workshop on corrosion, internal corrosion can affect the commodity being transported, flow velocity, and mode of operation. For the period 1998-2008, crude oil pipelines accounted for 85 percent of the significant internal corrosion accidents. In fact, the number of accidents due to internal corrosion exceeded those due to external corrosion in 2008.

Based upon the Volpe survey, the crude oil pipeline segment represented 69 percent of the Phase II mileage. There is some possible benefit if such pipelines were regulated. One pipeline operator has commented that there is no assessment of potential internal corrosion risk but that the cost for injection equipment, inhibitor, and monitoring equipment may be significant. The operator is presently reviewing those costs.

Breakout Tank Inspections

The frequency of in-service API 653 inspections for breakout tanks is expected to increase. The Volpe respondents with breakout tanks have tank integrity management programs and perform out-of-service inspections in accordance with API 653.

Public Awareness

A few well-publicized accidents have caused Congress, the public and regulators to react. Although rural low stress rulemaking had been under consideration for several years, it was the BP Alaska release that prompted Congress' action to direct the Department of Transportation regulations for rural low stress pipelines.

Since the Volpe respondents are already regulated, the operators have public awareness programs in place. Only one operator advised that they would have to expand their program in correspondence with increased mileage falling under regulation.

As part of the public awareness message, public officials, emergency responders, road agencies, local excavators, and landowners become aware of the presence and importance of such pipelines and will be able to appropriately react if a suspected release is detected.

A goal of the regulation is to provide assurance to the public of operators' continual commitment to pipeline safety.

Trained Workforce and Management of Change

Based upon the responses to the Volpe survey, the operator qualification requirements are not overly burdensome. However, such operators will likely face the same pressures of retaining a competent workforce since retirements, job position transfer, company acquisitions and divestitures, and labor mobility due to demand pose a significant challenge. The pressures and general conclusions are believed to be similar as expressed in the INGAA's study titled "Securing Our Future: Developing The Next Workforce: An Analysis Of Risk And Recommended Strategies for the Natural Gas Pipeline Industry", dated 2007. Continual training and recruitment of qualified personnel will similarly be required for operators of low stress pipelines. The Operator Qualification program may help to ensure that personnel responsible for various tasks are qualified and are able to recognize and appropriately react to abnormal conditions.

Other Hazardous Liquid Pipeline Commodities – Non-Regulated

Presently, PHMSA is regulating hazardous liquids such as petroleum, petroleum products, or anhydrous ammonia. There are other hazardous liquid commodities presently being transported including corrosive acid and caustic liquids. Olin Corporation Chlor-Alkali Division advertises on their website an "extensive pipeline network". Although such pipelines may be prohibited or excluded due to the Pipes Act of 2006, the pipeline transportation of such commodities may merit further study. It is expected that such pipelines would be low stress types. Summarized below are two incidents.

On September 5, 2009, it was reported to the National Response Center that a sodium hydroxide pipeline was struck by a contractor's lateral drilling rig during the installation of a natural gas line near Macintosh, Alabama. The pipeline released 10,000 pounds of sodium hydroxide into the soil. The pipeline is not presently regulated by DOT. The listed reason is "operator error". No additional details are provided on Incident Report #917006. It is not known whether the pipeline was adequately marked or Olin representatives were present during the drilling incident. However, Alabama One-Call law provides facilities the option of joining the One-Call Center or having their own One-Call center. However, Alabama One-Call website has a caveat that non-member facilities are not provided and it is the contractor's responsibility. Olin Corporation is not listed as a utility member on the Alabama One-Call website. If Olin's pipeline facilities were regulated under Part 195 then such facilities would be registered and the incident may have been avoided.

The second incident is a citation from the NRC's website regarding a benzene pipeline leak in Louisiana. On June 24, 2001 a spill of 22,000 gallons of benzene from a six inch pipeline was discovered in Geismar, LA. The material leaked out due to another pipeline releasing drops of nitric acid onto the benzene pipeline causing a hole. Only land was affected. The owner of the pipeline is ICOM, a private enterprise out of St. Gabriel, LA. State police, LA Department of Environmental Quality and clean up contractors are on scene. Media interest in the area is high. Clean up operations are ongoing. The environmental impact is unknown at this time. According to PotashCorp's website, they have a dedicated nitric acid pipeline. The regulatory status of the pipeline is not stated.

Additional Information on Incident Data

An overview of the pipeline operators that have been contacted for more information regarding the regulation of rural, low stress pipelines is provided in Exhibit 4-43. Each company, each person contacted and the number of attempts to attain information as well as a brief summary of the interview findings are summarized below. Overall, 21 companies were contacted and 14 provided additional information.

Exhibit 4-43: Pipeline Operators Contacted and Survey Result

Company	Survey Result
Praxair, Inc.	Praxair did not respond to follow-up. Excluded from analysis due short mileage and potential high stress pipe due to CO2 commodity.
BMC Holdings, Inc.	Excluded from rulemaking analysis due to finding that the line is permitted as "non-rural" with the Texas Railroad Commission. Informed BMC.
ExxonMobil US Production, a division of Exxon Mobil Corporation	Contacted operator. Used internal data for cost estimating purposes upon agreement with operator since operator did not have such data.
ConocoPhillips Alaska, Inc.	Contacted operator and confirmed Volpe survey information.
Montana Refining Company, Inc.	Not applicable to Phase II based upon review of Volpe data submittal.
Shell Pipeline Company, LP	Not applicable to Phase II based upon review of Volpe data submittal.
DCP Midstream	Reviewed data, website of operations and contacted DCP. Based upon data review, concluded that reported mileage is already regulated or excluded. Would not be subject to Phase II. DCP Midstream concurred.
Holly Energy Partners	Reviewed website of operations and Volpe survey data. Contacted operator and confirmed corrected mileage data based upon review of operator data. No cost impact.
ConocoPhillips Pipe Line	Unable to contact operator. Possible reorganization. Used information based upon Volpe survey and internal cost estimate factors for compliance.
Oiltanking Houston L.P.	Excluded from analysis due to mileage was less than threshold and non-applicability for potential rulemaking. Confirmed by review of 2008 annual report. Reviewed TRCC permit records. Permitted as non-rural.
BP	Contacted operator. Operator reanalyzed mileage data and concluded that potential Phase II regulations would have little cost impact.
Marathon Pipe Line LLC	Contacted operator. Operator unable to provide more detailed information on potential cost impact. Used internal cost factors.
Sunoco Pipeline LP	Contacted operator. Potential Phase II regulated mileage reduced from Volpe survey. Used cost data in absence of operator cost data with operator concurrence. Operator is reevaluating information.
ExxonMobil Pipeline Company	Contacted pipeline public information person per PHMSA website. Received phone call. Would have to refer request to others. Excluded mileage as Not-Applicable" due to review of Volpe data pending response. No call-back was received.
Mobil Pipe Line Company	Contacted pipeline public information official per PHMSA website. Received phone call. Would have to refer request to others. Excluded mileage as Not-Applicable" due to review of Volpe data pending response. No call-back was received.

Plains All American Pipeline, L.P.	Contacted operator. Operator had slightly revised mileage based upon further analysis. Revised cost impact based upon internal cost estimate factors and revised operator data.
McCain Pipeline Company	Contacted operator. Discussed potential cost impact. Agreed to use internal cost factors. Factors in agreement with operator's experience for such activities.
MarkWest Michigan Pipeline L.L.C.	Used conclusions for revised mileage and cost based upon e-mail from Lane Miller.
Westlake Petrochemicals	Reviewed website and annual report regarding operations. Contacted operator. Reviewed potentially mileage and pipelines with operator. Updated mileage. Discussed potential cost impacts due to regulation. Used internal estimates.
Chevron Pipe Line Company	Contacted operator. Mileage is best estimate at this time. Cost impact subject to operator review of records when rulemaking is known due to other priorities. Operator complies with Part 195.

Industry Data Observations

PPTS data indicators a reduction in incidents due to pipeline regulation over the past decade. The information collected from the 21companies contacted shows that although many operators are generally in accordance with Part 195 operations and maintenance practices, there are deemed improvements that operators can achieve. The cost and benefit will be dependent on each operator's situation.

More industry data can be collected in the future. There is a proposal for a selective operator study that surveys selected operators in order to close gaps in the Volpe survey. Central questions in this survey include:

- Do operators manage unregulated low stress pipelines differently from regulated lines, and if so how?
- If such lines are managed differently, what is the difference in cost per mile associated with managing those lines compared to regulated lines?
- What are the significant hurdles to bringing these unregulated lines into compliance?
- How would a "worst case" incident from an unregulated line compare to that of a currently regulated line?

The results of this survey will expand on the information summarized in the benefits section.

4.7 Summary of Benefits

Summary of Benefits

An examination of the costs of compliance and the current levels of compliance for individual pipelines revealed that pipelines fell into two distinct subgroups. The first group of pipelines was generally already in compliance with the regulations and faced small costs to comply with the proposed rulemaking. For operators that are largely in compliance and with few costs to implementation, the analysis assumes that the conservative trend line analysis benefit is the most appropriate measure of the benefits from regulation. The resulting benefits estimate for bringing pipelines already substantially in compliance into full compliance is $674 per mile. Of the 12 operators for which detailed cost information was available, seven have small or no compliance costs.

The second group of operators did not comply with the regulations and faced significant costs to comply with the proposed rulemaking. In some cases, operators that faced higher costs were smaller operators or operators who had recently purchased pipelines from previously unregulated smaller operators. To estimate the benefits for regulating these pipelines, an update of the 1990 ANPRM data for inflation and changes in pipeline practices and cleanup methods was used. The resulting benefits estimate for bringing pipelines not in compliance into full compliance is $21,055 per mile. This estimate was calculated by subtracting the cost of a fully regulated line ($615 as determined from PHMSA's 7000-1 incident database) from the estimated cost of an out of compliance line ($21,670 as explained in Exhibits 4-25 and 3-17). Of the 12 operators for which detailed cost information was available, five have relatively large compliance costs.

Assigning benefits in this manner is effective for weighing the mileage by expected benefits. The operators largely in compliance do not benefit as greatly from regulation, whereas operators with large implementation costs experience greater benefits from regulation.

Exhibit 4-44 provides the per mile benefit estimates for each alternative. The final per mile benefit for each alternative is a combination of the above benefits, $674 for largely in compliance lines and $21,055 for lines not in compliance. Exhibit 4-45 provides the total 30 year present value benefit estimates for each alternative. A detailed description of the estimation process for per mile benefits is provided for each of the Phase II alternatives as follows.

Exhibit 4-44: Per Mile Benefits by Alternative

Alternative	Annual Benefits ($/per mile)	
1. All low stress	$	11,266
2. Small diameter inside ½ mile of USA	$	12,167
3. Large diameter outside ½ mile of USA	$	13,247
4. Small diameter outside ½ mile of USA	$	7,305
5. All except Subpart H	$	7,404
6. All except the IMP	$	11,173

Alternative 1: All Eligible Low Stress Pipelines

The benefit estimate for Alternative 1 is calculated by summing the benefit estimates for Alternatives 2, 3, and 4. This provides the most detailed and comprehensive estimation of Alternative 1 because Alternatives 2, 3, and 4 are calculated by mileage segment, which is a more in-depth level of estimation. Summing the total 30 year present value benefit estimates for Alternatives 2, 3, and 4 results in a total 30 year present value benefit for Alternative 1 of $326.5 million. On an annual per mile basis, this is the equivalent of $11,266 per mile for Alternative 1. The per mile benefit of Alternative 1 is a weighted sum of the per mile benefits of Alternatives 2, 3 and 4.[42] As the benefit estimate for Alternative 1 is a summation of the benefits of all Phase II eligible segments, the detailed explanations of the benefit calculations for Alternatives 2, 3 and 4 follow below.

Alternative 2: Apply all Part 195 requirements to small diameter low stress pipelines within ½ mile of an USA

Of the 12 operators who responded to the follow up survey, six have small diameter low stress pipelines that are within ½ mile of an USA. In terms of compliance, approximately 25 percent of those miles are largely in compliance and 75 percent are substantially out of compliance (as shown in 3-16). Therefore, the two benefit estimates of $674 for substantially in compliance pipelines and $21,055 for out of compliance pipelines will be weighted by these respective percentages for small diameter low stress pipeline within ½ mile of an USA. However, the analysis cannot apply these percentages to the two benefit estimates directly. An evaluation of incident cost by diameter and pipeline segments within and outside ½ mile of USAs shows that each is different from incident costs over the entire system.

[42] $12,167*(100.5/1,384.3) + $13,247*(840.6/1,384.3) + $7,305*(443.2/1,384.3) = $11,266

Therefore, a determination of how the overall per mile benefits of \$674 and \$21,055 vary by diameter size, USA proximity classification, and Subpart is analyzed in the remaining five alternatives. The following methodology was utilized to make these calculations.

1. *Pipe Diameter* – To determine how the \$674 and \$21,055 per mile benefits differ for pipe diameter, two simultaneous linear equations are solved. The goal of this exercise is to determine the relative makeup of the overall estimated benefits in terms of small diameter benefit and large diameter benefit. The two equations are as follows:

$$\text{Equation 1: } (0.32)\,S + (0.68)\,L = 674$$
$$\text{Equation 2: } (1.77)\,S = L$$

   Equation 1 represents the makeup of the \$674 per mile benefit (\$21,055 could just as easily be substituted, but because the ultimate goal is to derive the relative small and large diameter percentages, either benefit figure can be used). S represents the per mile cost of small diameter pipe, and L represents the per mile cost of large diameter pipe. S and L are each weighted by the respective percentages of miles of each over the entire system. Approximately 32 percent of the entire system is comprised of small diameter pipe, and 68 percent of the system is comprised of large diameter pipe. These percentages are taken from the PHMSA 7000-1.1 Annual Report database for all pipelines in 2008 – there are approximately 35,499 miles of small diameter low stress pipeline and 76,258 miles of large diameter low stress pipeline. Therefore S is weighted by 0.32 and L by 0.68.

   Equation 2 represents the relative cost per mile of small and large diameter low stress pipeline incidents over the entire system. PHMSAs 7000-1 incident database shows over the period 2002 to 2008, small diameter incidents cost on average \$2,099 per mile and large diameter low stress pipeline incidents cost on average \$3,732 per mile. Therefore, large diameter low stress pipeline incidents are 1.77 times more costly per mile than small diameter low stress pipeline incidents.

   Solving the two equations simultaneously gives:

$$S = \$442$$
$$L = \$782$$

   Therefore, separating the overall \$674 substantially in compliance estimated benefit by diameter results in an estimated \$442 per mile benefit from regulating substantially in compliance small diameter pipe and \$782 per mile benefit from regulating substantially in compliance large diameter pipe. The \$442 small diameter pipe benefit estimate represents 66 percent of the overall benefit of \$674 for substantially in compliance pipelines. To determine the respective benefit small diameter low stress pipelines benefit for out of compliance pipelines, there are two options. The same simultaneous equation approach can be applied to \$21,055 in Equation 1, or the benefit can be estimated by applying the 66 percent to \$21,055. Either method results in a benefit of \$13,803 (correcting for rounding error) from regulating out of compliance small diameter pipeline.

   In conclusion, two benefit estimates were derived for small diameter pipe – substantially in compliance small diameter pipe and out of compliance small diameter pipe. This is the first step to estimating the Alternative 2 benefit. The second step, which follows next, is to determine how these two benefit estimates are calculated when USA proximity is included.

2. *USA Status* – An analysis of the high consequence area statistics in PHMSA's 7000-1 incident database is used to determine the benefit of small diameter pipe within ½ mile of an USA. As

explained in the analysis of PHMSA's database, USA proximity is not a field reported on the incident report form. Therefore, high consequence area status is used as a proxy for USA status. In terms of within ½ mile versus outside ½ mile of an USA, the potential difference in benefit can be attributed solely to the IMP because the IMP only applies to low stress pipelines within ½ mile of an USA.

As the IMP is a designed to detect and prevent corrosion, the approach taken to estimate benefits inside high consequence areas is to examine incidents caused by corrosion inside and outside of high consequence areas. In PHMSAs 7000-1.1 Annual Report on miles for 2008, there are 52,608 miles of estimated pipeline inside high consequence areas, and 58,325 miles outside high consequence areas. In PHMSA's 7000-1 incident database from 2002 to 2008, there were 102 corrosion-related incidents inside high consequence areas and 218 corrosion-related incidents outside high consequence areas. This is the same as 1.94 corrosion-related incidents per 1,000 miles within high consequence areas and 3.74 corrosion-related incidents per 1,000 miles outside of high consequence areas. Incident frequency is analyzed as opposed to incident cost because of the inherent cost bias in high consequence area incidents - the amount of resources directed at cleaning a high consequence area spill is greater than cleaning a spill in a non-high consequence area.

The difference in corrosion-related incidents per mile inside and outside high consequence areas is largely attributable to the IMP because the IMP is the only regulatory difference in the two areas. Therefore, the estimate is that the IMP prevents approximately 1.80 incidents per thousand miles, which is the difference in incidents per thousand miles within and outside of high consequence areas (3.74 - 1.94).

The trend line analysis attributes $346 of the total $674 per mile preventable costs to corrosion-related incidents: $318 per mile to external corrosion and $28 per mile to internal corrosion (provided in 4-45). Corrosion-related regulatory oversight includes Subpart F and Subpart H, with the IMP making up the vast majority of Subpart F costs. As explained above, the incident rate per thousand miles for lines without IMP (outside high consequence areas) is 3.74. To determine the additional incidents avoided by Subpart H, an estimate of pipeline incidents per thousand miles for a completely unregulated pipeline is necessary. In other words, the difference between the per thousand mile incident rate of a completely unregulated pipeline and the per thousand mile incident rate of a pipeline without IMP (3.74) will provide an estimate of additional incidents per thousand miles avoided by Subpart H.

To estimate the per thousand mile incident rate for a completely unregulated line, the average corrosion-related incident rate per thousand miles is multiplied by an unregulated factor. The average corrosion-related incident per thousand miles in the PHMSA's 7000-1 incident database is 2.88 (320 incidents over 110,933 miles). This is multiplied by the factor of unregulated corrosion incident costs to regulated corrosion incident costs, a proxy for additional costs associated with an unregulated (in terms of corrosion) pipeline. The factor is derived from the figures provided in Exhibit 4-39. The estimated corrosion-related incident costs from 1986 (419+55) are divided by the current 2008 corrosion-related incident costs (101+28). This factor is equal to 3.67. Multiplying the 3.67 unregulated factor by the average corrosion-related incident per thousand miles of 2.88 produces an unregulated (without Subpart H and without IMP) corrosion-related incident rate per thousand miles of approximately 10.60. Therefore, 1.80 (3.74 - 1.94) incidents per thousand miles are estimated as prevented by IMP and 6.86 (10.60 – 3.74) incidents per thousand miles are estimate as prevented by Subpart H. The remaining 1.94 incidents per thousand miles that occur within high consequence areas are assumed to be unpreventable incidents under current regulations.

Of the entire spectrum of corrosion-related incidents, therefore, approximately 18 percent (1.94/10.60) are unpreventable, 17 percent (1.8/10.60) are preventable by the IMP and 65 percent (6.86/10.60) are preventable by Subpart H. Within preventable incidents, the IMP prevents approximately 21 percent (1.8/8.66) while by Subpart H can prevent approximately 79 percent (6.86/8.66). Therefore, of the $346 corrosion-related costs per mile, approximately $71 is attributable to the IMP and $275 to Subpart H. Adding $71 in costs avoided by the IMP, realized on pipelines within ½ mile of USAs, to the $442 in costs avoided by regulating small diameter pipeline, gives $513 in costs avoided by regulating small diameter pipe within ½ mile of an USA. The $513 is approximately 76 percent of the overall $674 benefit from regulating a pipeline that is substantially in compliance. Applying 76 percent to the benefit of $21,055 from regulating a pipeline out of compliance, results in an estimate of approximately $16,032 per mile.

3. The final step in determining the Alternative 2 per mile benefit is to weight $513 and $16,032 by the proportion of operator miles that are substantially in compliance and out of compliance. As explained in the first paragraph of the Alternative 2 summary, these percentages are 25 percent and 75 percent respectively (shown in Exhibit 3-16). The benefit per mile is thus comprised of $128 ($513 x 0.25) from regulating substantially in compliance small diameter low stress pipeline within ½ mile of an USA and $12,039 ($16,032 x 0.75)[43] from the regulating out of compliance small diameter low stress pipelines within ½ mile of an USA. The final per mile benefit of Alternative 2 is the sum of these two figures: $12,167.

Alternative 3: Apply all Part 195 requirements to large diameter low stress pipelines outside ½ mile of an USA

The per mile benefit for large diameter low stress pipelines can be estimated using step 1 from Alternative 2. Solving the two simultaneous equations for L (large diameter pipe outside ½ mile of an USA) gives a per mile benefit estimate of $782 from regulating substantially in compliance large diameter pipelines. This is approximately 116 percent of the $674 trend line benefit. The corresponding benefit for out of compliance large diameter pipeline is 116 percent of $21,055 or $24,431.

Next, the two benefit estimates must be weighted by the proportion of large diameter low stress pipelines outside ½ mile of an USA that apply to substantially in compliance and out of compliance pipelines. These percentages are 47 and 53 respectively (as shown in Exhibit 3-16). The per mile benefit is thus comprised of $370 ($782 x 0.47) from regulating substantially in compliance large diameter low stress pipelines outside ½ mile of an USA and $12,877 ($24,431 x 0.53) from regulating out of compliance large diameter low stress pipelines outside ½ mile of an USA (corrected for rounding error). The final per mile benefit of Alternative 3 is $13,247.

Alternative 4: Apply all Part 195 requirements to small diameter low stress pipelines outside ½ mile of an USA

The per mile trend line benefit of small diameter low stress pipelines outside ½ mile of an USA was estimated in Alternative 2 step 1 above. The benefit is estimated to be $442 per mile. This is approximately 66 percent of the overall $674 benefit from regulating substantially in compliance pipeline. The corresponding benefit from regulating out of compliance pipeline is approximately 66 percent of $21,055, or $13,803.

The two benefit estimates must be weighted by the proportion of small diameter low stress pipelines outside ½ mile of an USA that apply to substantially in compliance and out of compliance pipelines.

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[43] Note: rounding errors are corrected for in the analysis and thus some presented calculations are slightly different from cited result.

These percentages are 49 and 51 respectively (as shown in Exhibit 3-16). The per mile benefit is thus comprised of $215 ($442 x 0.49) from regulating substantially in compliance small diameter low stress pipelines outside ½ mile of an USA and $7,091 ($13,803 x 0.51) from regulating out of compliance small diameter low stress pipelines outside ½ mile of an USA (corrected for rounding error). The final per mile benefit of Alternative 4 is $7,305.

Alternative 5: Apply all Part 195 requirements, except Subpart H (Corrosion Control), to all low stress pipelines not currently regulated

Subpart H is comprised of corrosion control measures. As explained in steps 2 and 3 of Alternative 2, the per mile benefit from Subpart H for pipelines substantially in compliance is $275, or approximately 41 percent of the total $674 benefit for lines substantially in compliance. Excluding it from the regulation, however, is equivalent to subtracting the $275 from $674. This is $399, or 59 percent of the $674 benefit from regulating lines substantially in compliance. The corresponding benefit for lines that are out of compliance is approximately 59 percent of $21,055, or $12,476 with no rounding error.

The two benefit estimates must be distributed by the proportion of all miles that apply to substantially in compliance and out of compliance pipelines. These percentages are 42 and 58 respectively (as shown in Exhibit 3-16). The per mile benefit is thus comprised of $168 ($399 x 0.42) from substantially in compliance pipelines without Subpart H and $7,236 ($12,476 x 0.58) from out of compliance pipelines without Subpart H (corrected for rounding error). The final per mile benefit of Alternative 5 is $7,404.

Alternative 6: Apply all Part 195 requirements, except the Integrity Management Program, to all low stress pipelines not currently regulated

Alternative 6 encompasses all eligible pipeline segments but excludes the IMP, which applies only to small diameter low stress pipelines within ½ mile of an USA. The benefit per mile is, therefore, a combination of the benefits from Alternatives 3 and 4, and a slightly modified benefit from Alternative 2. As explained in steps 2 and 3 of Alternative 2 above, the per mile benefit of IMP on substantially regulated pipelines is $71. This is approximately 11 percent of the overall benefit of $674 from bringing a substantially regulated line into full compliance. To estimate the benefit of Alternative 2 without the IMP, 11 percent of the $12,167 per mile benefit is removed. This figure, without rounding error, is $10,878 ($12,167 x 0.89).

The final calculation is a weighted average of Alternatives 3, 4 and the modified Alternative 2. The modified Alternative 2 per mile benefit of $10,878 is weighted by small diameter low stress pipeline within ½ mile of an USA (100.5/1,384.3), Alternative 3 per mile benefit of $13,247 is weighted by large diameter low stress pipelines outside ½ mile of an USA (840.6/1,384.3), and the Alternative 4 per mile benefit of $7,305 is weighted by small diameter low stress pipelines outside ½ mile of an USA (443.2/1,384.3). This weighted average is $11,173, and is the final per mile benefit of Alternative 6.

Exhibit 4-45 shows derivations of the 30 present value benefits for each alternative. The interest rate used to discount future cost outlays in this analysis is 2.7 percent, as required in the OMB Circular A-94. The estimated total 30 year present value benefits for each alternative in millions of dollars are provided in bold at the bottom of each table. The first column provides the years, the second column provides the per mile benefits for each year (also shown in Exhibits 4-44), and the third column provides the per mile present value of the benefit for each year when an annual discount rate of 2.7 percent is applied.

Exhibit 4-45: 30 Year Present Value Benefit Tables by Alternative

Alternative 1

Year	Per Mile Benefit	Per Mile PV
1	11,266	11,266
2	11,266	10,970
3	11,266	10,681
4	11,266	10,401
5	11,266	10,127
6	11,266	9,861
7	11,266	9,602
8	11,266	9,349
9	11,266	9,103
10	11,266	8,864
11	11,266	8,631
12	11,266	8,404
13	11,266	8,183
14	11,266	7,968
15	11,266	7,759
16	11,266	7,555
17	11,266	7,356
18	11,266	7,163
19	11,266	6,974
20	11,266	6,791
21	11,266	6,612
22	11,266	6,439
23	11,266	6,269
24	11,266	6,104
25	11,266	5,944
26	11,266	5,788
27	11,266	5,636
28	11,266	5,487
29	11,266	5,343
30	11,266	5,203
Per Mile 30 Year PV		235,834
Eligible Mileage		1384.3
Total 30 Year PV Benefit (In Millions)		**326.5**

Alternative 2

Year	Per Mile Benefit	Per Mile PV
1	12,167	12,167
2	12,167	11,847
3	12,167	11,536
4	12,167	11,232
5	12,167	10,937
6	12,167	10,650
7	12,167	10,370
8	12,167	10,097
9	12,167	9,831
10	12,167	9,573
11	12,167	9,321
12	12,167	9,076
13	12,167	8,838
14	12,167	8,605
15	12,167	8,379
16	12,167	8,159
17	12,167	7,944
18	12,167	7,735
19	12,167	7,532
20	12,167	7,334
21	12,167	7,141
22	12,167	6,954
23	12,167	6,771
24	12,167	6,593
25	12,167	6,419
26	12,167	6,251
27	12,167	6,086
28	12,167	5,926
29	12,167	5,770
30	12,167	5,619
Per Mile 30 Year PV		254,694
Eligible Mileage		100.5
Total 30 Year PV Benefit (In Millions)		**25.6**

Alternative 3

Year	Per Mile Benefit	Per Mile PV
1	13,247	13,247
2	13,247	12,899
3	13,247	12,559
4	13,247	12,229
5	13,247	11,908
6	13,247	11,595
7	13,247	11,290
8	13,247	10,993
9	13,247	10,704
10	13,247	10,423
11	13,247	10,149
12	13,247	9,882
13	13,247	9,622
14	13,247	9,369
15	13,247	9,123
16	13,247	8,883
17	13,247	8,649
18	13,247	8,422
19	13,247	8,201
20	13,247	7,985
21	13,247	7,775
22	13,247	7,571
23	13,247	7,372
24	13,247	7,178
25	13,247	6,989
26	13,247	6,805
27	13,247	6,626
28	13,247	6,452
29	13,247	6,283
30	13,247	6,117
Per Mile 30 Year PV		277,298
Eligible Mileage		840.6
Total 30 Year PV Benefit (In Millions)		**233.1**

Alternative 4

Year	Per Mile Benefit	Per Mile PV
1	7,305	7,305
2	7,305	7,113
3	7,305	6,926
4	7,305	6,744
5	7,305	6,567
6	7,305	6,394
7	7,305	6,226
8	7,305	6,062
9	7,305	5,903
10	7,305	5,748
11	7,305	5,597
12	7,305	5,450
13	7,305	5,306
14	7,305	5,167
15	7,305	5,031
16	7,305	4,899
17	7,305	4,770
18	7,305	4,645
19	7,305	4,522
20	7,305	4,404
21	7,305	4,288
22	7,305	4,175
23	7,305	4,065
24	7,305	3,958
25	7,305	3,854
26	7,305	3,753
27	7,305	3,654
28	7,305	3,558
29	7,305	3,465
30	7,305	3,374
Per Mile 30 Year PV		152,925
Eligible Mileage		443.2
Total 30 Year PV Benefit (In Millions)		**67.8**

Alternative 5

Year	Per Mile Benefit	Per Mile PV
1	7,404	7,404
2	7,404	7,209
3	7,404	7,019
4	7,404	6,835
5	7,404	6,655
6	7,404	6,480
7	7,404	6,310
8	7,404	6,144
9	7,404	5,982
10	7,404	5,825
11	7,404	5,672
12	7,404	5,523
13	7,404	5,378
14	7,404	5,236
15	7,404	5,099
16	7,404	4,965
17	7,404	4,834
18	7,404	4,707
19	7,404	4,583
20	7,404	4,463
21	7,404	4,345
22	7,404	4,231
23	7,404	4,120
24	7,404	4,012
25	7,404	3,906
26	7,404	3,804
27	7,404	3,704
28	7,404	3,606
29	7,404	3,511
30	7,404	3,419
Per Mile 30 Year PV		154,982
Eligible Mileage		1,384.3
Total 30 Year PV Benefit (In Millions)		**214.5**

Alternative 6

Year	Per Mile Benefit	Per Mile PV
1	11,173	11,173
2	11,173	10,879
3	11,173	10,593
4	11,173	10,314
5	11,173	10,043
6	11,173	9,779
7	11,173	9,522
8	11,173	9,272
9	11,173	9,028
10	11,173	8,791
11	11,173	8,560
12	11,173	8,335
13	11,173	8,115
14	11,173	7,902
15	11,173	7,694
16	11,173	7,492
17	11,173	7,295
18	11,173	7,103
19	11,173	6,917
20	11,173	6,735
21	11,173	6,558
22	11,173	6,385
23	11,173	6,217
24	11,173	6,054
25	11,173	5,895
26	11,173	5,740
27	11,173	5,589
28	11,173	5,442
29	11,173	5,299
30	11,173	5,160
Per Mile 30 Year PV		233,879
Eligible Mileage		1,384
Total 30 Year PV Benefit (In Millions)		**323.8**

5. NONTRADITIONAL BENEFITS

Introduction

In the previous chapter, emphasis had been placed on the evaluation of traditional benefits such as clean-up costs, cost of lost product and property damage cost, values based on available data and information from PHMSA's 7000-1 Hazardous Liquid Accident Report database. However, previous regulatory efforts by PHMSA have discussed a series of additional benefits: "Foremost among these is improved public confidence. There may also be benefits by preventing disruptions in fuel supply caused by pipeline failures. Supply disruptions also have national security implications, because they increase dependence on foreign sources of oil. Other benefits are expected to include avoided environmental and other damage from pipeline spills."[44] While the previous PHMSA regulatory analyses have not attempted to quantify these non-traditional benefits, this chapter examines each of these benefits in more detail and reviews case study attempts to quantify each benefit. The results of these literature reviews are used, where possible, to quantify each benefit. Where possible, the economic impacts of these non-traditional benefits are normalized to a spill unit value per-bbl or per-mile for this report. This chapter expands on the following non-traditional benefits:

- Prevention of Injury and Loss of Life
- Decrease Domestic Supply Disruption
- Decrease Dependency on Foreign Oil
- Additional Environmental Damages-Habitat Remediation
- Additional Environmental Damages- Air Pollution
- Federalization and Standardization
- Improvement of Public Confidence

5.1 Injury and Loss of Life

Description

A reduction in loss of life and in the number of injuries is a potential benefit from further regulating low stress pipelines.

Methodology

The US Department of Transportation (USDOT) provides an economic value for each human injury and fatality prevented.[45] The total value of injuries and fatalities prevented from the regulation of low stress pipelines can be calculated by multiplying the USDOT economic values by the number of injuries and fatalities prevented by regulation.

[44] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration. "Phase I – Regulatory Analysis". August 2006.

[45] USDOT, Office of the Secretary of Transportation Memorandum on "Treatment of the Economic Value of a Statistical Life in Departmental Analyses – 2009 Annual Revision," March 18, 2009. http://ostpxweb.dot.gov/policy/reports/VSLpercent20Guidancepercent20031809percent20a.pdf

Evidence

The USDOT annually updates its estimate of the economic value of preventing a human fatality. Estimates of the value of a statistical life (VSL) are derived from the concept of individual willingness to pay (WTP) for small reductions in risk.[46] Estimates of income elasticity are based on studies conducted in several countries at different times, so that the incomes reflected in meta-analyses have multiple sources. Per-capita is measured by real income growth by the Wages and Salaries component of the Employment Cost Index, in constant dollars deflated by the CPI-U, and derive its effect on VSL by the stated elasticity.[47] These VSLs are adjusted to 2007 prices by the CPI-U and range from $2.6 million to $8.5 million.[48] The mean of the five values is $5.8 million, which appropriately reflects the conclusions of recent studies as well as the practice of other agencies. Adjusted for inflation, the VSL was estimated as $6 million in 2009. The value of injuries prevented is measured as a fraction of the VSL depending on the type of injury prevented. Injuries are categorized on the Maximum Abbreviated Injury Scale (MAIS).

Exhibit 5-1 provides a description of injury severity ranked by MAIS level and the corresponding ratio of VSL. For example; a moderate injury is equivalent to the MAIS level 2 rating and carries a injury prevention value of $93,000, which is a 0.0155 fraction of the value of a statistical life (VSL).

Exhibit 5-1: Relative Disutility Factors by MAIS Injury Severity Level

MAIS Level	Injury Severity	Fraction of VSL	Value of Injury Prevention ($2009)
1	Minor	0.0020	12,000
2	Moderate	0.0155	93,000
3	Serious	0.0575	345,000
4	Severe	0.1875	1,125,000
5	Critical	0.7625	4,575,000
6	Fatal	1.0000	6,000,000

The number of injuries and deaths on hazardous liquid pipelines is collected by PHMSA and available in the 7000-1 incident database. However, as discussed in the previous chapter, the low stress incidents cannot be divided between regulated and unregulated with complete certainty. Therefore, an estimate is made across the entire range of low stress incidents. For the 117 low stress incidents there are no deaths or injuries. To make an estimate, data on 1,113 incidents from 2002-2008 are used.

[46] Ibid
[47] Ibid
[48] Ibid

Exhibit 5-2: Hazardous Liquid Pipeline Operators Accident Summary Statistics

Year	Fatalities	Injuries	Net Loss (Bbls)
2002	1	0	77,316
2003	0	5	50,528
2004	5	16	68,563
2005	2	2	45,839
2006	0	2	54,004
2007	4	10	68,707
2008	2	2	95,473
Total	14	37	460,430

Using Exhibit 5-2, a summary from the PHMSA database for all pipeline incidents in the past seven years, a per-mile estimate for a loss of life is calculated.[49] The number of fatalities per mile per year is 0.00012. The cost per mile per year for fatalities is $720. To calculate the cost per year for low stress pipelines, 4,817 low stress miles from Volpe[50] are used and the VSL used is $6 million. This yields a low stress fatality prevention cost of $1,135,135 a year. The net present value over 30 years with a discount rate of 2.7 percent is approximately $23,137,000. The net present value over 50 years with a discount rate of 2.7 percent is approximately $30,946,000. This is provided in Exhibit 5-3.

Exhibit 5-3: Fatality Cost Estimates

Cost of Fatality per Year ($2009)	Cost of Fatality over 30 Years Assuming a 2.7percent Discount Rate	Cost of Fatality per Year 50 Years from now Assuming a 2.7percent Discount Rate
$1,135,135	$23,137,000	$30,946,000

The value of injury prevented for *all* pipeline incidents is calculated using the average value of injury prevention. Since there was no specification of the severity of injury in the data, the average value of injury prevention is used, which is $1.2 million. The number of fatalities per mile per year is 0.00033. The cost per mile per year for injuries is $396. To calculate the cost per year for low stress pipelines, the low stress miles are assumed to be 1,500 and the cost of injury prevention is $1.2 million per fatality. This yields a low stress injury prevention cost of $594,000 a year. The net present value for 30 years with a discount rate of 2.7 percent is approximately $11,190,000. The net present value for 50 years with a discount rate of 2.7 percent is approximately $14,967,000. This is displayed in Exhibit 5-4.

Exhibit 5-4: Injury Cost Estimates

Cost of Injury per Year($2009)	Cost of Injury per Year 30 Years from now Assuming a 2.7percent Discount Rate	Cost of Injury per Year 50 Years from now Assuming a 2.7percent Discount Rate
$594,000	$11,190,000	$14,967,000

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[49] PHMSA, "Hazardous Liquid Pipeline Operators Accident Summary Statistics by Year". May 2009. http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc. Page 1.

[50] Volpe "Rural Low Stress Hazardous Liquid Pipelines Survey, Summary of Results Including Late Responders." Transmitted from Carson Poe of Volpe to Cheryl Whetsel of PHMSA on July 27, 2009 9:54 am Eastern.

Summary

No deaths or injuries were reported in low stress pipeline incidents over the past seven years. The value of a fatality prevented for all pipeline incidents is $1,135,135. The cost per mile per year of fatalities prevented is $720. The value of an injury prevented for all pipeline incidents is $594,000. The cost per mile per year for injuries is $396.

Key Data Sources

USDOT, Office of the Secretary of Transportation Memorandum on "Treatment of the Economic Value of a Statistical Life in Departmental Analyses – 2009 Annual Revision," March 18, 2009. http://ostpxweb.dot.gov/policy/reports/VSLpercent20Guidancepercent20031809percent20a.pdf

PHMSA, PHMSA F 7000-1 (1-2001; Accident Report Form)

5.2 Energy Security-Domestic Supply Disruption

The nation's energy system is a complex, interconnected network in which a disruption in one part of the infrastructure can easily cause disruptions elsewhere in the system. After September 11, 2001, there has been increased attention on the system's vulnerability to intentional attack, accident or natural disaster. The health of the U.S. economy is intimately linked with energy resources and assets such as power plants, power lines and fuel pipelines, and fuel processing and storage centers. These assets comprise a large portion of the nation's critical infrastructure, and any disruption to these assets could adversely affect the economy. In this chapter two main issues of energy security are addressed. This section examines the effects of a domestic supply disruption and the following section examines U.S. dependency on foreign oil.

Description

The potential energy security benefit from regulation stems from a reduction in short-term supply disruption and oil product shortages. A large incident on a prominent low stress pipeline may cause a loss of productivity and economic profit for pipeline operators. Furthermore, the costs are not limited to pipeline operators, as a disruption in the pipeline system can affect the entire chain of suppliers and consumers.

Methodology

Three studies are provided to estimate a per-bbl cost of disruption and adjustment. A study conducted by the RAND Corporation concludes that domestic supply disruptions are not economically significant, whereas studies by the National Academy of Sciences and the Oak Ridge National Laboratory (ORLN) suggest the opposite. Using the estimates of the two latter studies, a per-bbl cost of disruption and adjustment is derived.

Evidence- Case Study 1

The first study titled "Imported Oil and U.S. National Security" and published by the RAND Corporation in 2009 discusses past supply disruptions, the consequences, and the likelihood of future happenings. Following Hurricane Katrina, crude oil from offshore rigs could not be landed, refinery operations were stopped, and pipelines were inoperable due to power outages. These events caused sharp increases in the prices of gasoline and diesel.[51]

However, the study emphasizes the resiliency of the US supply chain: "The U.S. domestic supply chain for petroleum products is robust. Accelerated repairs of breakdowns, increased imports of refined oil products, and alternative domestic sources of supply make it highly unlikely that interruptions in domestic supplies could severely disrupt the U.S. economy".[52] Scarcity can be shared throughout the market, and there are many methods of transport in the event of a pipeline breakdown, including barge, train, and truck.[53] The study concludes that such supply disruptions are not of great consequence to economic productivity.

While the RAND study states that the disruption in oil supply has economically insignificant effects, there is still an adjustment cost, which includes the social cost of a disruption in oil supply. While there is no data available for a domestic supply disruption, inferences can be made from the cost of a disruption in U.S. oil imports. A sudden a disruption in world oil supplies has two main effects: it reduces the level of output that the U.S. economy can produce using its available resources; and it causes temporary dislocation and underutilization of available resources, such as labor and plant capacity.

Evidence –Case Studies 2 and 3

While one low stress pipeline incident may not have as great an impact on the economy as a disruption in U.S. oil imports, there are still adjustment costs associated with a pipeline failure. The two studies described below provide a per-bbl estimate of these disruption and adjustment costs.

The 2007 study on energy security benefits conducted by ORNL is split into two parts; one part discusses the disruption and adjustment costs and the second part discusses the dependency on foreign oil. The first part of this ORNL study will be used in this section and the second part regarding the dependency on foreign oil will be addressed in the next section of this chapter.

The ORNL study estimates that under reasonable assumptions about the probability that world supplies will be disrupted to varying degrees in the future, the disruption and adjustment component of the cost of U.S. oil imports will be between $2.18 and $7.81 per-bbl of oil.[54] Adjustment costs will account for the largest share of this per-bbl estimate. To further support this claim, a study conducted by the National Academy of Sciences in 2009 titled "Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use" states that "estimates in the literature of the macroeconomic costs of disruption and adjustments range from $2 to $8 per-bbl"[55] with an average cost of $5 per-bbl.

From the 7000-1 database, current low stress pipeline average net loss is 80 bbl. For these 80 bbls spilled there is a disruption and adjustment cost between $160 and $640 per incident with a mean value of $400 per incident.

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[51] Crane, Keith and Andreas Goldthau, Michael Toman, Thomas Light, Stuart E. Johnson, Alireza Nader, Angel Rabasa, Harun Dogo. "Imported Oil and U.S. National Security." Rand Infrastructure, Safety, & Environment; National Security Research Division, 2009.Page 22.

[52] Ibid. Page 14.

[53] Ibid. Page 22.

[54] Leiby, Paul. Oak Ridge National Laboratory. "Estimating the Energy Security Benefits of Reduced U.S. Oil Imports", February 2007. http://www.epa.gov/OTAQ/renewablefuels/ornl-tm-2007-028.pdf. Page 5.

[55] National Academy of Sciences. "Hidden Cost if Energy: Unpriced Consequences of Energy Production and Use", 2009. http://www.nap.edu/catalogue/12794.html. Page 15.

The yearly cost of disruption and adjustment is $7,000 for all low stress pipelines, assuming that the average amount spilled per year for all low stress pipelines is 1,400 bbls and the average cost of disruption and adjustment is $5 per-bbl. The net present value over thirty years with a discount rate of 2.7 percent is approximately $142,700. The net present value over fifty years with a discount rate of 2.7 percent is approximately $190,900. This is displayed in Exhibit 5-5.

Exhibit 5-5: Disruption and Adjustment Cost Estimates

Disruption and Adjustment Cost per Year($2009)	Disruption and Adjustment Cost over 30 Years Assuming a 2.7percent Discount Rate	Disruption and Adjustment Cost over 50 Years Assuming a 2.7percent Discount Rate
$7,000	$142,700	$190,900

Since the 117 low stress incidents used occurred on regulated pipelines, it can be assumed that the cost is higher for an unregulated incident. The larger spill size would increase the overall adjustment and disruption cost for all unregulated low stress pipeline incidents. Assuming that 240 bbls were spilled in an unregulated incident, or 3 times the amount reported in the 7000-1, the total cost of one spill would increase to an estimated $480- $1920 per incident with a mean of $1200 per incident. The benefit of regulation is the difference between the two cost estimates, which at a mean value is $800 per incident.

Summary

The RAND study states that the disruption in oil supply has economically insignificant effects. The ORNL and the National Academy of Science Study estimate the average disruption and adjustment cost per-bbl to be $5. The average total disruption and adjustment cost for low stress pipeline incidents is $400 per incident.

Key Data Sources

Crane, Keith and Andreas Goldthau, Michael Toman, Thomas Light, Stuart E. Johnson, Alireza Nader, Angel Rabasa, Harun Dogo. "Imported Oil and U.S. National Security." Rand Infrastructure, Safety, & Environment; National Security Research Division, 2009.

Leiby, Paul. Oak Ridge National Laboratory. "Estimating the Energy Security Benefits of Reduced U.S. Oil Imports", February 2007. http://www.epa.gov/OTAQ/renewablefuels/ornl-tm-2007-028.pdf

National Academy of Sciences. "Hidden Cost if Energy: Unpriced Consequences of Energy Production and Use", 2009. http://www.nap.edu/catalogue/12794.html

PHMSA, PHMSA F 7000-1 (1-2001; Accident Report Form)

5.3 Energy Security - Dependency on Foreign Oil

Description

A second component of energy security is dependence on foreign oil. Following a spill, there is an increased demand for oil to replace lost product. To meet this demand, additional oil is either imported or supplied domestically.

Methodology

Three different case studies, one conducted by the RAND corporation and two conducted by the Oak Ridge National Laboratory (ORNL), are used to provide greater insight into U.S foreign oil dependency and to calculate an energy security benefit of reducing imports on a per-bbl basis.

Evidence-Case Study 1

As discussed in the 2009 RAND study on oil's relevance to national security, the majority of US petroleum products are imported – 58 percent in 2007 and the U.S. Department of Transportation's Energy Information Administration (USDOT EIA) projects imports at above 50 percent of total supply for at least the next 20 years.[56] Therefore, an increase in demand for oil necessitates an increase in U.S. dependency for foreign oil. Not only are oil products a large percentage of imports, but the relative cost compared to other imported commodities is very high: "Imports of oil and refined oil products totaled $333 billion in 2007, accounting for 16.5 percent of total U.S. imports. Of this total, $253 billion consisted of imports of crude oil. In contrast, imports of aluminum were only $4.4 billion, and imports of uranium, zinc, and nickel were less than $1 billion combined."[57]

Evidence-Case Study 2

Oil dependency, as defined in a 2005 ORNL study on the costs of US oil dependence, is "the vulnerability to economic costs caused by the use of market power by oil producing companies. This definition includes more than the costs of disruptions caused by oil price shocks. It includes the loss of output due to higher than competitive market prices and the transfer of wealth from oil consumers to oil producers as a result of monopolistic pricing."[58] According to ORNL, the cost of oil dependency from 1970 to 2005 is roughly $8 trillion, with a reasonable range of uncertainty from $5 trillion to $13 trillion.[59] Adjusting this for inflation using the Bureau of Economic Analysis Implicit Price Deflator for GDP[60], the cost of oil dependency in 2009 is $8.6 trillion, with a range of uncertainty from $5.4 trillion to $14 trillion.

To estimate the per-bbl energy security cost (in terms of oil dependency) using the ORNL's $8 trillion estimate, a total bbls (bbl) imported figure from 1970 to 2005 is required. The EIA provides a database listing the yearly number of imported bbls since 1981.[61] Exhibit 5-6 gives a summary of these statistics:

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[56] Crane, Keith and Andreas Goldthau, Michael Toman, Thomas Light, Stuart E. Johnson, Alireza Nader, Angel Rabasa, Harun Dogo. "Imported Oil and U.S. National Security." Rand Infrastructure, Safety, & Environment; National Security Research Division, 2009. Page 6.
[57] Ibid. Page 7.
[58] Greene, David L. and Sanjana Ahmad. "Cost of U.S. Oil Dependence: 2005 update." Oak Ridge National Laboratory, February 2005. http://cta.ornl.gov/cta/Publications/Reports/ORNL_TM2005_45.pdf. Page 7.
[59] Ibid. Page 45.
[60]Implicit Price Deflators for Gross Domestic Product." Bureau of economic Analysis, September 30, 2009. http://www.bea.gov/national/nipaweb/TableView.asp?SelectedTable=13&ViewSeries=NO&Jaa=no&Request3Pl&3Place=N&FromView=YES&Freq=Year&FirstYear=1990&LastYear=2009&3Place=N&Update=Update&JavaBox=no#Mid
[61] "US. Imports of Crude Oil and Petroleum Products (Thousand Bbls)." Energy Information Administration,official Energy Statistics from the U.S. Government, June 29, 2009. http://tonto.eia.doe.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=mttimus1&f=a

Exhibit 5-6: U.S. Imports of Crude Oil and Petroleum Products (Thousand BBLs)

Average per year	1970 to 1980	2,193,272
	1981 to 1990	2,302,454
	1991 to 2000	3,456,719
	2001 to 2005	4,566,944
	1970 to 2005	**3,129,847**
Sum	Sum 1970 to 1980	24,125,992
	Sum 1981 to 1990	23,024,540
	Sum 1991 to 2000	34,567,192
	Sum 2001 to 2005	22,834,722
	Sum 1970 to 2005	**104,552,446**

The total number of bbls imported between 1970 and 2005 is 104.6 billion bbls. Applying the ORNL estimate of the total cost of oil dependency between 1970 and 2005 and expanding the EIA's estimate of the total number of bbls imported to cover these same years, the energy cost in terms of oil dependency is $82 per-bbl in 2009.

Evidence-Case Study 3

As cited in the 2007 ORNL study, the energy security benefits in dollars per-bbl of reducing imports is $13.58 (in $2006)[62] or $14.10 per-bbl (in $2009) adjusted for inflation using the BEA GDP price deflator. This estimate is far less than the calculation above. However, the 2005 ORNL study uses the total value of a bbl of oil. On the other hand, the 2007 ORNL study uses the marginal "premium" approach, which identifies those energy-security related costs which are not reflected in the market price of oil, and which are expected to change in response to an incremental change in the level of oil use.[63]

One way to reconcile the 2007 ORNL energy security benefit of $14.10 per-bbl with the 2005 ORNL benefit of $82 per-bbl is to assume the 2005 ORNL study includes the full price paid for the barrel of oil. If this is true, the total price paid (which is not considered an energy security premium), is $4.3 trillion (the average market price of oil from 1970-2005 [$42][64] multiplied by bbls imported from 1970-2005 [104.5 billion bbls]). Using the mean value 2005 ORNL oil dependency cost estimate of $5 trillion, the energy security premium, or the marginal energy security cost, is $0.7 trillion. Dividing this by the total number of bbls imported between 1970 and 2005 yields a result of $6.69 in energy security cost per-bbl, which comes close to the $14.10 per-bbl estimate.

Other factors that might explain the discrepancy between the $82 and $14.10 benefits are the exclusion of market relationships from in the 2007 ORNL study. Possible changes in market relationships, such as increased or decreased flexibility of demand and supply and amplifying or offsetting policies by other oil importing countries, might strongly influence oil security costs.[65]

Conclusively, the 2007 ORNL study's estimate of $14.10 ($2009) per-bbl of reducing imports only reflects the energy security benefit, whereas the $82 ($2009) of the 2005 ORNL study is an estimate of the per-bbl energy cost that includes numerous factors such as the loss of output and the transfer of wealth

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[62] Leiby, Paul. Oak Ridge National Laboratory. "Estimating the Energy Security Benefits of Reduced U.S. Oil Imports", February 2007. http://www.epa.gov/OTAQ/renewablefuels/ornl-tm-2007-028.pdf

[63] Ibid

[64] Adjusted for inflation, estimated value for 2009

[65] Leiby, Paul.Oak Ridge National Laboratories. "Estimating the Energy Security Benefits of Reduced U.S. Oil Imports", February 2007. http://www.epa.gov/OTAQ/renewablefuels/ornl-tm-2007-028.pdf

from oil consumers to oil producers due to monopolistic pricing. An appropriate estimate for the per-bbl energy security cost is the average of these two values, $48.03 per-bbl.

The yearly cost of energy security for a low stress pipeline system that averages 1,400 bbls spilled per year is $67,200. The net present value over thirty years with a discount rate of 2.7 percent is approximately $1,366,000. The net present value over fifty years with a discount rate of 2.7 percent is approximately $1,827,000. This is displayed in Exhibit 5-7.

Exhibit 5-7: Energy Security Cost Estimates

Energy Security Cost per Year($2009)	Energy Security Cost over 30 Years Assuming a 2.7percent Discount Rate	Energy Security Cost over 50 Years Assuming a 2.7percent Discount Rate
$67,000	$1,366,000	$1,827,000

Summary

The 2007 ORNL study estimate of energy security benefits of reducing imports is $14.10 per-bbl. The 2005 ORNL study estimates the cost of energy in terms of oil dependency to be $82 per-bbl. The 2005 ORNL study includes numerous market relationships, which are excluded in the 2007 ORNL study. An appropriate estimate for the per-bbl energy security benefits is the average of these two values: $48.03 per-bbl.

Key Data Sources

Crane, Keith and Andreas Goldthau, Michael Toman, Thomas Light, Stuart E. Johnson, Alireza Nader, Angel Rabasa, Harun Dogo. "Imported Oil and U.S. National Security." Rand Infrastructure, Safety, & Environment; National Security Research Division, 2009.

Greene, David L. and Sanjana Ahmad. "Cost of U.S. Oil Dependence: 2005 update." Oak Ridge National Laboratory, February 2005. http://cta.ornl.gov/cta/Publications/Reports/ORNL_TM2005_45.pdf

Leiby, Paul.Oak Ridge National Laboratories. "Estimating the Energy Security Benefits of Reduced U.S. Oil Imports", February 2007. http://www.epa.gov/OTAQ/renewablefuels/ornl-tm-2007-028.pdf

"US. Imports of Crude Oil and Petroleum Products (Thousand Bbls)." Energy Information Administration, official Energy Statistics from the U.S. Government, June 29, 2009. http://tonto.eia.doe.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=mttimus1&f=a

"The Price of Oil: Is History Repeating Itself?" Global Financial Data. http://74.125.113.132/search?q=cache:9CF_sa4HBsJ:https://www.globalfinancialdata.com/articles/Oil_Is_History_Repeating_Itself.doc+average+import+price+of+bbl+of+oil+last+30+years&cd=

5.4 Additional Environmental Impacts-Habitat Remediation

The values in this section are the incremental additional environmental damages that are not included in the traditional benefits. Incremental additional environmental costs include recreational values—the value associated with use of an environment—and existence values—the value associated with the existence of an environment (e.g. having a nice view). Such values are exclusively measured through surveys. By using valuation estimates from sites that have similar geographic, demographic and environmental characteristics, these values can be partially quantified. The additional environmental impacts discussed in this report are those of habitat and aquatic remediation as well as air pollution.

Description

The environmental impacts of a pipeline spill in the proximity of an USA such as woodlands, marshes and fisheries, are numerous and range from loss of animals and potentially endangered species to a loss in recreational value. It is difficult to determine the actual damage estimate, cost and success rate of habitat remediation since there are multiple sources of uncertainty. As stated by the U.S. Fish and Wildlife Services, there exists "a lack of detailed injury data (e.g., the precise change in ecosystem function resulting from a release, or the exact geographic area over which injury has occurred) and there is no measurement for the likely effectiveness of spill cleanup activities or a hazardous waste site remedy. Furthermore, it is unknown whether, and at what rate, natural recovery will occur and there is a lack of information regarding the likely effectiveness of natural resource restoration activities and the reliability/accuracy of existing economic benefit estimates."[66]

According to the 7000-1 data, there are uncertainties with the implementation and reporting of the habitat remediation process. In many incidents where there had been no overall remediation listed, the fish, birds and soil categories clearly stated a need for remediation. Furthermore, the time frame for reporting on the remediation process according to the 7000-1 data set is limited to 30 days after the incident. However, clean-up time and remediation efforts could extend far beyond a 30 day period and therefore affect total clean-up cost and increase the value of additional ecological damage.

Methodology

In order to provide a mechanism for comparing costs from different sized oil spills, economic impacts were normalized to a spill unit value (per-bbl) basis for this report. The social value of additional ecological damage after an oil-spill will be the central value assessed in this section.

The social value for the purpose of this report will encompass option, existence, bequest and other values which do not involve active user participation. Most economists recognize that a person's option to visit an environmentally unspoiled area may have monetary value. At present the only available methodology for measuring these values is contingent valuation (CV), which attempts to create a hypothetical market for non-use natural resource services by providing respondents with the opportunity to buy or sell the services in question.

The benefits transfer method, using the data of three major oil spills in the past two decades, will be used to estimate the value of additional ecological damage per-bbl spilled. Furthermore the estimates for the total cost of remediation from these three oil spill incidents respectively will be used, since the total cost of remediation of a habitat is not clearly defined and is a combination of the cost of factors such as bioremediation, surface washing, industrial cleaning and replacement of wildlife.

Evidence-Case Study 1

The first incident that will be examined is the *Exxon Valdez* oil spill in 1989. Using data collected in a study in January 2009, an estimate for the additional social value of ecological damage per-bbl spilled is derived. The study states that the average cost of remediation per gallon spilled is $582[67] or $24,444 per-bbl excluding what was termed the ecological damage factor. When this factor, which gives an appropriate estimate of the social value of ecological damage, is added in to the equation, the average cost

[66] "Addressing Uncertainty and Data Limitation in Damage Assessment." U.S. Fish and Wildlife Services. http://74.125.113.132/search?q=cache:uYSvazDUIB0J:policy.fws.gov/NRDA- Page 2.
[67] Victoria Transport Policy Institute,"Water Pollution and Hydrologic Impacts." http://www.fws.gov/policy/NRDA-7.pdf, Page 5.

for remediation is $728 per gallon[68] or $30,576 per-bbl. It can be inferred that the social cost for ecological damage remediation comes to an average of $6,216 per-bbl. This additional social cost for environmental damage accounts for 20 percent of the $30,576 total remediation cost.

Evidence-Case Study 2

A case study of the 1990 Arthur Kill incident shows a similar conclusion. The direct use, non-use and total damages from the Exxon Arthur kill oil spill are summarized in Exhibit 5-8.[69] The values for non-use damages are used to estimate the additional social cost associated with the environmental damage caused by an oil spill. Existence value and recreational value reflect the social value of environmental damage and these damages are best summarized in the non-use damages column.

Exhibit 5-8: Arthur Kill: Total Damages, Direct Use and Non-Use Damages

	Cleanup Costs	Capital Losses	Prevention Costs	NRDA Assessment Costs	Direct Use Damages	Non-Use Damages (Wetland Services)	Non-Use Damages (Existence, Option)	Total
Total (Million $)	18	0.2	25	0.6-2.8	0.046	0.525	5.0-20.0	49-66
Per bbl	1,427	16	1,981	126	4	42	409-1,584	3,907-5,259

Total remediation costs are estimated to range from $49 million to $66 million, largely depending on non-use damages. Total non-use damages range from $5-$20 million ($409 to $1,584 per barrel), which accounts for 11percent-31percent of total cost.

In a different case study on the Arthur Kill incident, the average social value is estimated at $16 million, which falls into the same range. [70]

Evidence- Case Study 3

A third example is the Texaco Anacortes spill and Exhibit 5-9[71] provides a summary of all costs. The total remediation costs for this spill were estimated at $9,425,000, of which non-use damages were estimated to be $500,000. In per-bbl terms the total cost is $1,885 and the non-use damage per-bbl is $100. Non-use damages, which are a good reflection of the social value of environmental damage, account for 5percent of total remediation costs.

Exhibit 5-9: Texaco Anacortes: Total Cost and Non-Use Damages

	Cleanup Costs	Prevention Costs	Non-Use Damages	Total Cost
Total	$8,125,000	$800,000	$500,000	$9,425,000
Per bbl	$1,652	$160	$100	$1,885

After analyzing all three examples, the additional environmental damages estimates range from 5percent-31percent of total cost. Using the 7000-1 data, the average total cost per low stress pipeline spill is roughly $177,000. The total remediation cost is $66,000, or approximately 40 percent of total costs.

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[68] Ibid

[69] Advanced Resources International "Economic Impact on Oil Spills: Spill Unit Costs for Tankers, Pipelines, Refineries and Offshore Facilities". http://www.osti.gov/bridge/purl.cover.jsp?purl=/10186611-aXJ8ID/native/ Page 72

[70] Addressing Uncertainty and Data Limitation in Damage Assessment. http://74.125.113.132/search?q=cache:uYSvazDUIB0J:policy.fws.gov/NRDA- Page 17

[71] Ibid. Page 83.

While issues are raised in the traditional benefits chapter 4 with the remediation costs field, it is an issue with the cost numbers not being large enough. Therefore, the $66,000 can be used as a low end estimate. The average net amount spilled per low stress incident is 81 bbls. From this, the average total cost comes to $814 per-bbl. Using the estimated range of 5percent-31percent, the dollar amount of the additional social value of environmental damages is $41 - $252 per-bbl for an incident occurring on a low stress pipeline. The average social value of environmental damages is thus $146.5 per-bbl.

The yearly total social value of environmental damages is $205,100 for low stress pipelines, assuming that the average amount spilled per year for low stress pipelines is 1,400 bbls and average social value of environmental damages is $146.5 per-bbl. The net present value over thirty years with a discount rate of 2.7percent is approximately $4,181,000. The net present value over fifty years with a discount rate of 2.7percent is approximately $5,591,000. This is displayed in Exhibit 5-10.

Exhibit 5-10: Social Value of Environmental Cost Estimates

Social Value of Environmental Damage per Year($2009)	Social Value of Environmental Damage over 30 Years Assuming a 2.7percent Discount Rate	Social Value of Environmental Damage over 50 Years Assuming a 2.7percent Discount Rate
$205,100	$4,181,000	$5,591,000

Limitations

The success rate of measuring the remediation of an area after an oil spill also varies as in some instances a recovery of 55 percent of the affected area to its original status and in other cases a 90 percent recovery of the affected area to its original status is considered a "success" according to the Inter Press Service (IPS) in a case study on Cuba.[72] It is difficult to gather information on the success rate of the recovery of an affected after a spill, as the definition of what constitutes a success varies widely.

Summary

The additional, non-use environmental damages estimates range from 5 percent to 31 percent of total remediation costs. Using the 7000-1 data, the additional social values of environmental damages is $41 - $252 per-bbl for an incident occurring on a low stress pipeline. The average social value of environmental damages is $146.5 per-bbl.

Key Data Sources

Advanced Resources International "Economic Impact on Oil Spills: Spill Unit Costs for Tankers, Pipelines, Refineries and Offshore Facilities". http://www.osti.gov/bridge/purl.cover.jsp?purl=/10186611-aXJ8ID/native/

Addressing Uncertainty and Data Limitation in Damage Assessment. http://74.125.113.132/search?q=cache:uYSvazDUIB0J:policy.fws.gov/NRDA-7

Victoria Transport Policy Institute."Water Pollution and Hydrologic Impacts". http://www.vtpi.org/tca/tca0515.pdf

PHMSA, PHMSA F 7000-1 (1-2001; Accident Report Form)

[72] IPS-News. http://ipsnews.net/news.asp?idnews=30079

5.5 Additional Environmental Impacts - Air Pollution

Description

The burning of crude oil emits pollutants into the air that have damaging effects on the environment and on air quality. The social value of having clean air will is the potential benefit from regulation.

Methodology

To value the additional social costs of air pollution per-bbl, a series of linkages are made between emissions and the dollar-value of environmental damage. Important to note, however, is that in all incidents reported, there has only been one explosion of a pipeline.

Evidence

A study on the hidden cost of energy has estimated that the marginal climate damage is \$30/ton CO_2-eq[73]. From the 7000-1 data we know that the average spill size per low stress incident is 80 bbls and we will use this as an estimate of the amount of oil that was lost during the explosion since no data on lost oil is available for that incident. Additionally, 3.15 bbls of crude oil are equal to1 ton of CO_2 emission.[74] In one low stress pipeline explosion incident roughly 26 tons of CO_2 are emitted into the atmosphere. At a cost of \$30/ton CO_2 emission, the social value of clean air in one low stress pipeline explosion is \$762 or \$9.52 per-bbl.

Summary
At a cost of \$30/ton CO2 emission, the social value of decreasing air pollution of one regulated low stress pipeline explosion is \$9.52 per-bbl.

5.6 Standardization and Federalization

Description

This section outlines the economic benefits of standardization and federalization. There exist potential savings from a more complete federal coverage and from the standardization of regulations across pipeline sub-categories.

Methodology

By analyzing three different reports on federal versus state regulation, conclusions about the benefits of federalization and standardization can be extrapolated.

Evidence - Case Study 1

The appropriate role of the Department of Transportation (DOT) versus that of the states in the regulation of pipeline safety and the enforcement of operating standards is a topic of continuing debate. In the mid 1990s the Clinton Administration sought to enhance state oversight, e.g., inspection of interstate pipeline transportation, but it wanted to ensure that the safety regulation of interstate operations remained solely a

[73] National Academy of Sciences. "Hidden Cost of Energy: Unpriced Consequences of Energy Production and Use", 2009. http://www.nap.edu/catalogue/12794.html. Page 15.
[74] Bliss, Jim. "Carbon dioxide emissions per-bbl of crude oil". March 2008. http://numero57.net/?p=255. Page 1.

federal function. The Office of Pipeline Safety (OPS), within the Department of Transportation (DOT), is the lead federal regulator of pipeline safety. The OPS uses a variety of strategies to promote compliance with its safety regulations, including inspections, investigation of safety incidents, and maintaining a dialogue with pipeline operators.[75] The agency clarifies its regulatory expectations through a range of communications and relies upon a range of enforcement actions to ensure that pipeline operators correct safety violations and take preventative measures to preclude future problems.[76]

The state must adopt the minimum federal regulations and may adopt more stringent regulations for intrastate pipelines as long as the state regulations are not incompatible with federal regulations. [77] Under certification, a state has responsibility for enforcement of regulations on intrastate pipelines. Experience has proven this approach practical.[78]

However, as oversight of the federal role in pipeline safety and security continues, questions may be raised concerning the effectiveness of state pipeline damage prevention programs, federal pipeline safety enforcement, the relationship between DHS and DOT with respect to pipeline security, and particular provisions in federal pipeline safety regulation.[79]

Evidence - Case Study 2

The regulation of low stress pipelines continuously comes under scrutiny, especially after events such as the BP pipeline spill that led to a partial shutdown of the Prudhoe Bay area oil field on the North Slope of Alaska in 2006.

Furthermore, BP clearly treated its non-federally regulated "transit" pipelines differently than those transmission pipelines that were regulated, with troubling results. When U.S. DOT surveyed pipeline operators in 1992, it found that 84percent of the low-pressure pipeline mileage nationwide was not operated in compliance with the requirements of the electronic code of federal regulations 49 CFR 195[80].

The costs for compliance with a more comprehensive standardization scheme would not be large, especially given the high costs to society when pipelines fail. PHMSA predicts that this standardization scheme will cost operators only $17 million, a relatively small amount given the *likely higher costs to society* from higher fuel costs, lost taxes, cleanup costs (including governmental oversight), etc. when pipelines like BP's fail[81].

Evidence - Case Study 3

Standardization of safety and response policies across states could lead to potential cost reductions. In a survey conducted in Europe within various companies the effects of standardization were discussed and standardization was always equated with a reduction in transaction costs.[82] Standardizing procedures from emergency response to safety regulations across states can lead to a reduction in transaction costs. Furthermore, time could be saved by standardizing report fillings into national databases.

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[75] Parfomak, Paul. "Pipeline Safety and Security: Federal Programs". February 2008. Page 1.
[76] Ibid. Page 1.
[77] Pipeline Safety Trust. "State Pipeline Safety Policy". http://www.pstrust.org/resources/regs/state_pol.htm.
[78] Pipeline Safety Trust. "State Pipeline Safety Policy" http://www.pstrust.org/resources/regs/state_pol.htm. Page 1.
[79] Parfomak, Paul. "Pipeline Safety and Security: Federal Programs". February 2008.
[80] BP Pipeline Failure: Its Effects on Oil Supply and How to Prevent a Recurrence: Hearing. Before the S. Comm. on Energy and Natural Resource, 109th Cong. 24 (2006) (statement of Peter Van Tuyn). Page 20
[81] Ibid. Page 25
[82] DIN German Institute for Standardization. "Economic Benefits of Standardization". http://docs.google.com/gview?a=v&q=cache:3Lg1oavarHQJ:www.din.de/sixcms_upload/media/2896. Page 13.

The European study also shows that companies participating in standardization measures have more of a say in the adoption of a national standard[83]. When a legislative body requires a technical rule, it will frequently turn to standards. If a company has been actively involved in developing these standards, it can adopt the standard before it becomes law, avoiding costs which would otherwise be incurred at a later stage. 25 percent of the businesses surveyed had already chosen such a strategy at least once[84]. Of these, 36 percent had been able to make large to very large savings[85]. This principle could be applied to the standardization of pipeline safety and response regulations across states. Should there occur a change in the federal legislation, states will not only have more input into federal rule making regarding pipeline policies, but could potentially save money.

Summary

There exist potential savings from the standardization of regulations across pipeline sub categories. Case Study 2 states that the costs for compliance with a more comprehensive standardization scheme would not be large and not having this standardization results in likely higher costs to society. Case Study 3suggests reduced transaction costs through standardization and suggests increased participation of states in the federal legislative process regarding pipeline safety and response standardization.

Key Data Sources

"Economic Evaluation of Regulating Certain Hazardous Pipelines Operating at 20 percent or Less of Specified Minimum Yield Strength," by Deanna Mirsky (EG&G/Dynatrend) and The Hazardous Materials Transportation Special projects Office VNTSC. July 21, 1992. Docket: PHMSA-RSPA-2003-15864-0034:

Pipeline Safety Trust. "State Pipeline Safety Policy". ttp://www.pstrust.org/resources/regs/state_pol.htm

Parfomak, Paul. "Pipeline Safety and Security: Federal Programs". February 2008.

BP Pipeline Failure: Its Effects on Oil Supply and How to Prevent a Recurrence: Hearing before the S. Comm. on Energy and Natural Resource, 109th Cong. 24 (2006) (statement of Peter Van Tuyn)

DIN German Institute for Standardization. "Economic Benefits of Standardization". http://docs.google.com/gview?a=v&q=cache:3Lg1oavarHQJ:www.din.de/sixcms_upload/media/2896/economic_benefits_standardization.pdf+When+a+legislative+body+requires+a+technical+rule,+it+will+frequently+turn+to+standards.+If+a+company+has+been+actively+involved+in+developing+these+standards,+it+can+adopt+the+standard+before+it+becomes+law,+avoiding+costs+which+would+otherwise+be+incurred+at+a+later+stage.&hl=en&gl=us&pid=bl&srcid=ADGEEShog4mhNt9oJOzUjDzjWDT3wG2rnI1BJgXoSFH8jUHhSkUBUocvtOVROiG1lsoa7pGfya9Hv_A6ZU5ivwU8LSvdtZlF153H_NtcMIjJ7b8vKMzLPYaPquN62hKA92l0ANi_GjaK&sig=AFQjCNHARsgrPa8LMOG_tUKstf3-jnI0SA

[83] Ibid. Page 10
[84] Ibid. Page 10
[85] Ibid. Page 10

5.7 Public Confidence

Description

Public confidence in pipeline safety has been shaken by major incidents in recent years. Those incidents have generated concerns among public interest groups, the National Transportation Safety Board, and Congress, as well as the public at large, and have prompted PHMSA to issue several new regulations. Under current regulations, portions of low stress lines located in areas where product spills resulting from incidents could potentially cause environmental damage or other harm are not subject to pipeline safety regulations. PHMSA emphasized in the Phase I regulatory analysis that public confidence is very important and changes must be made so that the public can live, work, and congregate near pipelines and have increased confidence that their safety is assured.

Methodology

Since it is difficult to quantify the loss of confidence, the benefit transfer methodology will be used to estimate the per-bbl loss in public confidence after an oil-spill. A study on the effects of terrorism on public confidence will be used for this purpose. Furthermore, a second approach to quantifying the effects of a low stress pipeline spill on public confidence will be implemented using a second study. Estimates in loss of public confidence are positively correlated to the decline in residential property values located in close proximity to a pipeline incident.

Evidence – Case Study 1

A study conducted in 2008 titled "The Effect of Terrorism on Public Confidence: An Exploratory Study", asked individuals to ascribe a monetary value to a loss or gain in confidence, whereas the value associated with a loss is greater than the value associated with a gain. When respondents were asked to quantify the value of a permanent incremental change in confidence to be based on a time-defined portion of their salary, responses ranged from 2 hours to 25 years (52,000 hours) of salary for an increase and from 1 hour to 100 years (208,000 hours) for a decrease.[86] Because of the small sample size and wide variation of responses, the median value is believed to represent a more accurate measure of central tendency than the mean. The median responses were 780 and 2,631 hours, respectively.[87] Based on median income data from the U.S. Census Bureau, the median hourly wage for an American worker is $15.45. Thus, the per-capita estimated value of a single-point increase in confidence is $12,050, and it is $40,650 for a single-point decrease.[88]

For the attack scenarios used in this study, the net loss in value for a single refinery bombing is $2.4 trillion (17percent of GDP).[89] While it is assumed that any pipeline incident would result in a smaller loss in public confidence than a large-scale terrorist attack, the numbers in this study can still be used as an estimate.

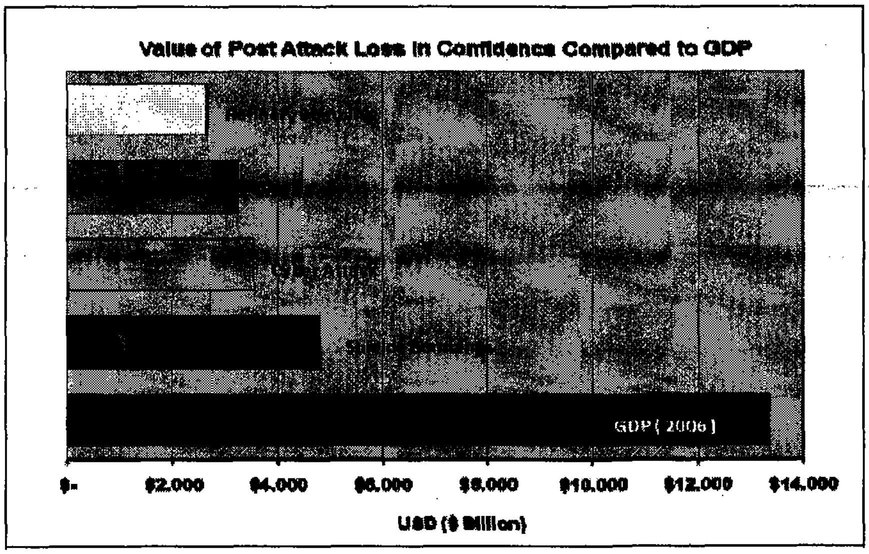
[86]Argonne National Laboratory (AGN),"The Effect of Terrorism on Public Confidence: An ExploratoryStudy," 2008

[87] Ibid. Page 20.

[88] Ibid. Page 20.

[89] Ibid. Page 23.

Exhibit 5-11: Population-wide Net Value of Loss in Confidence with GDP Comparison



Source: BEA, 2008

Exhibit 5-11 shows that the loss in public confidence nationwide from a refinery bombing is $2.4 trillion in a population of 218 million adults. This is the same as $11,009 loss in confidence for the average person. For the purpose of this analysis, the assumption is made that the capacity of the average oil refinery per day is 127,272 b.p.d.[90] This means there is a loss in confidence of 8 cents per person per-bbl spilled. From the 7000-1 database, 1,400 bbls a year are spilled on low stress pipeline incidents. The loss of public confidence per person per-bbl per year is $0.08 divided by 365 because it is a one-time figure. This figure is $0.0002. Assuming that between 50,000-100,000 people heard about these low stress pipeline incident in the news, the loss in public confidence for 1400 bbls spilled in one year lies between $14,893- $29,782.

The average value of total loss in public confidence per year is $23,000. The net present value over thirty years with a discount rate of 2.7 percent is approximately $468,800. The net present value over fifty years with a discount rate of 2.7 percent is approximately $627,000. This is displayed in Exhibit 5-12.

Exhibit 5-12: Public Confidence Cost Estimates

Public Confidence Cost per Year($2009)	Public Confidence Cost over 30 Years Assuming a 2.7percent Discount Rate	Public Confidence Cost over 50 Years Assuming a 2.7percent Discount Rate
$23,000	$468,800	$627,000

Evidence – Case Study 2

A different approach to quantifying the effects of a low stress pipeline spill on public confidence is to acknowledge a correlation in the rise or decline in public confidence with a rise or decline in residential property values located in close proximity to the pipeline incident.

[90] Energy Information Administration. "Refinery Capacity Report". January, 2009. http://www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcapacity.html

One study by ECONorthwest and another study by Resource and Energy Economics evaluated the impact of a pipeline on the property values of adjacent and nearby properties. This was measured by using hedonic housing prices to evaluate the extent to which proximity to the pipeline is associated with differences in sales price of a single family home. Both studies found that the proximity to a pipeline has no statistically significant or economically significant impact on residential property values, since for each additional 100 feet of distance from the pipeline the selling price decreased by less than one-tenth of one percent.[91]

However, a study titled "A Meta-Analysis of the Effect of Environmental Contamination and Positive Amenities on Residential Real Estate Values" evaluated the effects of contamination on property values. This study claims that there is an average loss of 9.5 percent of the home value with a typical distance of slightly less than two miles from the source of contamination[92]. A regression analysis in the study shows being 2 miles from the source of contamination results in a mean loss of 4percent in home value[93].

Using the 2009 average housing price of $325,000 from the Global Property Guide[94], we find that the average loss in housing price per low stress pipeline incident is $13,000 - $30,875 using the average loss percentage of 4 percent-9.5 percent. From the 7000-1 database, the average spill size is 80 bbls per low-spill incident leading to a value reduction per house of $160 - $381 per-bbl. The average value reduction per house is $270.5 per-bbl, which can be used as a proxy for loss in public confidence.

Suggestions

Additionally, it is critical to develop a comprehensive oil spill crisis management program and to prepare a media and public relations plan in order to positively influence public confidence. Outlining a policy for media interaction and developing a proactive plan for working with the media to disseminate timely, positive information during a spill can greatly increase public confidence.

The economics of spill response weigh in favor of being prepared. With increasing regulations and regulatory fines, the price for being unprepared can be substantial, and the environmental impact can be great. Investing in a contingency plan, training, and the appropriate in-house and contractor resources is an inexpensive hedge against a potentially costly incident. While there is no quantitative data available for the improvement of public confidence through the implementation of response programs, numerous studies have shown that such programs have a positive effect on public confidence, thereby lowering the cost associated with a lack of public confidence.

Summary

Case study 1 estimates a loss in confidence of $0.08 per person per-bbl spilled in one day. From the example in case study 1, the average loss in public confidence for 1359 bbls spilled in one year in a regulated low stress pipeline incident lies between $14,893- $29,7826. Case Study 2 suggests a value reduction per house of $162.5 - $385.93 per-bbl spilled. This is similar to an average loss in confidence per household of $274 per-bbl spilled.

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[91] ECONorthwest."Natural Gas Pipelines and Residential Property Values: Evidence from Clackamas and Washington Countries. February 2008. Page 12.
[92] Simons. "A Meta-Analysis of the Effect of Environmental Contamination and Positive Amenities on Residential Real Estate Values.". 2009. http://redorbit.com/modules/news/tools.php?toll=print&id=424785. Page 6.
[93] Ibid. Page 11.
[94] Global Property Guide. http://www.globalpropertyguide.com/real-estate-house-prices/U

5.8 Summary

The exhibit below provides a summary of estimated non-traditional benefits associated with Phase II regulation.

Exhibit 5-13: Summary Chart for Non-Traditional Benefits

Non-Traditional Benefits		
Benefit	**Average Cost Per-Bbl**	**Average Cost Per Mile per Year**
Prevention of Injury and Loss of Life		
1. Death		$720
2. Injury		$396
Social Value of Energy Security		
1. Domestic Supply Disruption	$5	
2. U.S. Dependency on Foreign Oil	$48.03	
Avoidance of Additional Environmental Costs		
1.Habitat Remediation	$146.5	
2. Air Pollution	$9.25	
Federalization and Standardization	Not quantifiable	
Improvement of Public Confidence	$270.5	
1. Case Study 1 (Terrorism)	$0.08 per person/per day	
2. Case Study 2 (Housing prices)	$274 per household	

This chapter has examined more closely the non-traditional benefits associated with hazardous liquid low stress pipeline regulation. While the previous PHMSA regulatory analyses have not attempted to quantify these non-traditional benefits, this chapter has successfully quantified each benefit using case studies and the results of these literature reviews. The economic impacts of these non-traditional benefits are normalized to a spill unit value per-bbl or per-mile basis for this report and summarized Exhibit 5-13. Overall, for every section outlined in this chapter, there are great benefits associated with a regulation in hazardous low stress pipelines. The overall cost estimates for low stress pipelines with lengths of 1500 miles-year for each section are summarized in the Exhibit 5-14 below: The benefit for each would be the avoided cost with implementation of the pipeline regulation.

Exhibit 5-14: Summary of Cost per year and Net Present Values

	Cost per year	**Cost over 30 Years NPV**	**Cost over 50 Years NPV**
Fatality	$1,135,135	$23,137,000	$30,946,000
Injury	$594,000	$11,190,000	$14,967,000
Disruption and Adjustment	$7,000	$142,700	$190,900
Energy Security	$67,000	$1,366,000	$1,827,000
Social Value of Environmental Damage	$205,100	$4,181,000	$5,591,000
Public Confidence	$23,000	$468,800	$627,000

According to OMB Circular A-4, it will not always be possible to express in monetary units all of the important benefits and costs. In such cases, OMB recommends that agencies should exercise professional judgment in determining how important the non-quantified benefits or costs may be in the context of the overall analysis. If the non-quantified benefits and costs are likely to be important, agencies should carry out a "threshold" analysis to evaluate their significance. In addition to threshold analysis agencies should indicate, where possible, which non-quantified effects are most important and why.

In the case of the proposed regulation, non-quantified benefits are likely to be significant. For example, estimates of additional environmental costs were 5 to 31 percent of traditional incident costs. These non-traditional benefits, however, are not likely to vary significantly by alternative on a percentage basis. Therefore, they would not alter the basic ranking of the alternatives. If non-traditional benefits were included, it would increase the final benefit estimates increasing the already positive net benefits.

Appendix A: Applicable Pipelines

§ 195.1 Which pipelines are covered by this part?

(a) *Covered.* Except for the pipelines listed in paragraph (b) of this section, this part applies to pipeline facilities and the transportation of hazardous liquids or carbon dioxide associated with those facilities in or affecting interstate or foreign commerce, including pipeline facilities on the Outer Continental Shelf (OCS). This includes:

(1) Any pipeline that transports a highly volatile liquid (HVL);

(2) Transportation through any pipeline, other than a gathering line, that has a maximum operating pressure (MOP) greater than 20-percent of the specified minimum yield strength;

(3) Any pipeline segment that crosses a waterway currently used for commercial navigation;

(4) Transportation of petroleum in any of the following onshore gathering lines:

(i) A pipeline located in a non-rural area;

(ii) To the extent provided in §195.11, a regulated rural gathering line defined in §195.11; or

(iii) To the extent provided in §195.413, a pipeline located in an inlet of the Gulf of Mexico.

(5) Transportation of a hazardous liquid or carbon dioxide through a low stress pipeline or segment of pipeline that:

(i) Is in a non-rural area; or

(ii) Meets the criteria defined in §195.12(a).

(6) For purposes of the reporting requirements in subpart B, a rural low stress pipeline of any diameter.

(b) *Excepted.* This part does not apply to any of the following:

(1) Transportation of a hazardous liquid transported in a gaseous state;

(2) Transportation of a hazardous liquid through a pipeline by gravity;

(3) A pipeline subject to safety regulations of the U.S. Coast Guard;

(4) A low stress pipeline that serves refining, manufacturing, or truck, rail, or vessel terminal facilities, if the pipeline is less than one mile long (measured outside facility grounds) and does not cross an offshore area or a waterway currently used for commercial navigation;

(5) Transportation of hazardous liquid or carbon dioxide in an offshore pipeline in State waters where the pipeline is located upstream from the outlet flange of the following farthest downstream facility: The facility where hydrocarbons or carbon dioxide are produced or the facility where produced hydrocarbons or carbon dioxide are first separated, dehydrated, or otherwise processed;

(6) Transportation of hazardous liquid or carbon dioxide in a pipeline on the OCS where the pipeline is located upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator;

(7) A pipeline segment upstream (generally seaward) of the last valve on the last production facility on the OCS where a pipeline on the OCS is producer-operated and crosses into State waters without first connecting to a transporting operator's facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. A producing operator of a segment falling within this exception may petition the Administrator, under §190.9 of this chapter, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance;

(8) Transportation of a hazardous liquid or carbon dioxide through onshore production (including flow lines), refining, or manufacturing facilities or storage or in-plant piping systems associated with such facilities;

(9) Transportation of a hazardous liquid or carbon dioxide:

(i) By vessel, aircraft, tank truck, tank car, or other non-pipeline mode of transportation; or

(ii) Through facilities located on the grounds of a materials transportation terminal if the facilities are used exclusively to transfer hazardous liquid or carbon dioxide between non-pipeline modes of transportation or between a non-pipeline mode and a pipeline. These facilities do not include any device and associated piping that are necessary to control pressure in the pipeline under §195.406(b); or

(10) Transportation of carbon dioxide downstream from the applicable following point:

(i) The inlet of a compressor used in the injection of carbon dioxide for oil recovery operations, or the point where recycled carbon dioxide enters the injection system, whichever is farther upstream; or

(ii) The connection of the first branch pipeline in the production field where the pipeline transports carbon dioxide to an injection well or to a header or manifold from which a pipeline branches to an injection well.

(c) *Breakout tanks.* Breakout tanks subject to this part must comply with requirements that apply specifically to breakout tanks and, to the extent applicable, with requirements that apply to pipeline systems and pipeline facilities. If a conflict exists between a requirement that applies specifically to breakout tanks and a requirement that applies to pipeline systems or pipeline facilities, the requirement that applies specifically to breakout tanks prevails. Anhydrous ammonia breakout tanks need not comply with §§195.132(b), 195.205(b), 195.242 (c) and (d), 195.264(b) and (e), 195.307, 195.428(c) and (d), and 195.432(b) and (c). [73 FR 31644, June 3, 2008]

Appendix B: Regulated Rural Gathering Lines

§ 195.11 What is a regulated rural gathering line and what requirements apply?

Each operator of a regulated rural gathering line, as defined in paragraph (a) of this section, must comply with the safety requirements described in paragraph (b) of this section.

(a) *Definition.* As used in this section, a regulated rural gathering line means an onshore gathering line in a rural area that meets all of the following criteria—

(1) Has a nominal diameter from 6⅝ inches (168 mm) to 8⅝ inches (219.1 mm);

(2) Is located in or within one-quarter mile (.40 km) of an unusually sensitive area as defined in §195.6; and

(3) Operates at a maximum pressure established under §195.406 corresponding to—

(i) A stress level greater than 20-percent of the specified minimum yield strength of the line pipe; or

(ii) If the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure of more than 125 psi (861 kPa) gage.

(b) *Safety requirements.* Each operator must prepare, follow, and maintain written procedures to carry out the requirements of this section. Except for the requirements in paragraphs (b)(2), (b)(3), (b)(9) and (b)(10) of this section, the safety requirements apply to all materials of construction.

(1) Identify all segments of pipeline meeting the criteria in paragraph (a) of this section before April 3, 2009.

(2) For steel pipelines constructed, replaced, relocated, or otherwise changed after July 3, 2009, design, install, construct, initially inspect, and initially test the pipeline in compliance with this part, unless the pipeline is converted under §195.5.

(3) For non-steel pipelines constructed after July 3, 2009, notify the Administrator according to §195.8.

(4) Beginning no later than January 3, 2009, comply with the reporting requirements in subpart B of this part.

(5) Establish the maximum operating pressure of the pipeline according to §195.406 before transportation begins, or if the pipeline exists on July 3, 2008, before July 3, 2009.

(6) Install line markers according to §195.410 before transportation begins, or if the pipeline exists on July 3, 2008, before July 3, 2009. Continue to maintain line markers in compliance with §195.410.

(7) Establish a continuing public education program in compliance with §195.440 before transportation begins, or if the pipeline exists on July 3, 2008, before January 3, 2010. Continue to carry out such program in compliance with §195.440.

(8) Establish a damage prevention program in compliance with §195.442 before transportation begins, or if the pipeline exists on July 3, 2008, before July 3, 2009. Continue to carry out such program in compliance with §195.442.

(9) For steel pipelines, comply with subpart H of this part, except corrosion control is not required for pipelines existing on July 3, 2008 before July 3, 2011.

(10) For steel pipelines, establish and follow a comprehensive and effective program to continuously identify operating conditions that could contribute to internal corrosion. The program must include measures to prevent and mitigate internal corrosion, such as cleaning the pipeline and using inhibitors. This program must be established before transportation begins or if the pipeline exists on July 3, 2008, before July 3, 2009.

(11) To comply with the Operator Qualification program requirements in subpart G of this part, have a written description of the processes used to carry out the requirements in §195.505 to determine the qualification of persons performing operations and maintenance tasks. These processes must be established before transportation begins or if the pipeline exists on July 3, 2008, before July 3, 2009.

(c) *New unusually sensitive areas.* If, after July 3, 2008, a new unusually sensitive area is identified and a segment of pipeline becomes regulated as a result, except for the requirements of paragraphs (b)(9) and (b)(10) of this section, the operator must implement the requirements in paragraphs (b)(2) through (b)(11) of this section for the affected segment within 6 months of identification. For steel pipelines, comply with the deadlines in paragraph (b)(9) and (b)(10).

(d) *Record Retention.* An operator must maintain records demonstrating compliance with each requirement according to the following schedule.

(1) An operator must maintain the segment identification records required in paragraph (b)(1) of this section and the records required to comply with (b)(10) of this section, for the life of the pipe.

(2) An operator must maintain the records necessary to demonstrate compliance with each requirement in paragraphs (b)(2) through (b)(9), and (b)(11) of this section according to the record retention requirements of the referenced section or subpart.

[73 FR 31644, June 3, 2008]

Appendix C: low stress pipeline Requirements in Rural Areas

§ 195.12 What requirements apply to low stress pipelines in rural areas?

(a) *General.* This section does not apply to a rural low stress pipeline regulated under this part as a low stress pipeline that crosses a waterway currently used for commercial navigation. An operator of a rural low stress pipeline meeting the following criteria must comply with the safety requirements described in paragraph (b) of this section. The pipeline:

(1) Has a nominal diameter of 8⅝ inches (219.1 mm) or more;

(2) Is located in or within a half mile (.80 km) of an unusually sensitive area (USA) as defined in §195.6; and

(3) Operates at a maximum pressure established under §195.406 corresponding to:

(i) A stress level equal to or less than 20-percent of the specified minimum yield strength of the line pipe; or

(ii) If the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure equal to or less than 125 psi (861 kPa) gage.

(b) *Requirements.* An operator of a pipeline meeting the criteria in paragraph (a) of this section must comply with the following safety requirements and compliance deadlines.

(1) Identify all segments of pipeline meeting the criteria in paragraph (a) of this section before April 3, 2009.

(2) Beginning no later than January 3, 2009, comply with the reporting requirements of subpart B for the identified segments.

(3)

(i) Establish a written program in compliance with §195.452 before July 3, 2009, to assure the integrity of the low stress pipeline segments. Continue to carry out such program in compliance with §195.452.

(ii) To carry out the integrity management requirements in §195.452, an operator may conduct a determination per §195.452(a) in lieu of the half mile buffer.

(iii) Complete the baseline assessment of all segments in accordance with §195.452(c) before July 3, 2015, and complete at least 50-percent of the assessments, beginning with the highest risk pipe, before January 3, 2012.

(4) Comply with all other safety requirements of this part, except subpart H, before July 3, 2009. Comply with subpart H before July 3, 2011.

(c) *Economic compliance burden.*

(1) An operator may notify PHMSA in accordance with §195.452(m) of a situation meeting the following criteria:

(i) The pipeline meets the criteria in paragraph (a) of this section;

(ii) The pipeline carries crude oil from a production facility;

(iii) The pipeline, when in operation, operates at a flow rate less than or equal to 14,000 barrels per day; and

(iv) The operator determines it would abandon or shut-down the pipeline as a result of the economic burden to comply with the assessment requirements in §§195.452(d) or 195.452(j).

(2) A notification submitted under this provision must include, at minimum, the following information about the pipeline: its operating, maintenance and leak history; the estimated cost to comply with the integrity assessment requirements (with a brief description of the basis for the estimate); the estimated amount of production from affected wells per year, whether wells will be shut in or alternate transportation used, and if alternate transportation will be used, the estimated cost to do so.

(3) When an operator notifies PHMSA in accordance with paragraph (c)(1) of this section, PHMSA will stay compliant with §§195.452(d) and 195.452(j)(3) until it has completed an analysis of the notification. PHMSA will consult the Department of Energy (DOE), as appropriate, to help analyze the potential energy impact of loss of the pipeline. Based on the analysis, PHMSA may grant the operator a special permit to allow continued operation of the pipeline subject to alternative safety requirements.

(d) *New unusually sensitive areas.* If, after July 3, 2008, an operator identifies a new unusually sensitive area and a segment of pipeline meets the criteria in paragraph (a) of this section, the operator must take the following actions:

1) Except for paragraph (b)(2) of this section and the requirements of subpart H, comply with all other safety requirements of this part before July 3, 2009. Comply with subpart H before July 3, 2011.

(2) Establish the program required in paragraph (b)(2)(i) within 12 months following the date the area is identified. Continue to carry out such program in compliance with §195.452; and

(3) Complete the baseline assessment required by paragraph (b)(2)(ii) of this section according to the schedule in §195.452(d)(3).

(d) *Record Retention.* An operator must maintain records demonstrating compliance with each requirement according to the following schedule.

(1) An operator must maintain the segment identification records required in paragraph (b)(1) of this section for the life of the pipe.

(2) An operator must maintain the records necessary to demonstrate compliance with each requirement in paragraphs (b)(2) through (b)(4) of this section according to the record retention requirements of the referenced section or subpart.

[73 FR 31644, June 3, 2008]

Appendix D: Definitions

§ 195.2 Definitions

Abandoned means permanently removed from service.

Administrator means the Administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate.

Barrel means a unit of measurement equal to 42 U.S. standard gallons.

Breakout tank means a tank used to (a) relieve surges in a hazardous liquid pipeline system or (b) receive and store hazardous liquid transported by a pipeline for reinjection and continued transportation by pipeline.

Carbon dioxide means a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state.

Component means any part of a pipeline which may be subjected to pump pressure including, but not limited to, pipe, valves, elbows, tees, flanges, and closures.

Computation Pipeline Monitoring (CPM) means a software-based monitoring tool that alerts the pipeline dispatcher of a possible pipeline operating anomaly that may be indicative of a commodity release.

Corrosive product means "corrosive material" as defined by §173.136 Class 8–Definitions of this chapter.

Exposed underwater pipeline means an underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from mean low water.

Flammable product means "flammable liquid" as defined by §173.120 Class 3–Definitions of this chapter.

Gathering line means a pipeline 219.1 mm (8⅝in) or less nominal outside diameter that transports petroleum from a production facility.

Gulf of Mexico and its inlets means the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.

Hazard to navigation means, for the purposes of this part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from the mean low water.

Hazardous liquid means petroleum, petroleum products, or anhydrous ammonia.

Highly volatile liquid or *HVL* means a hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 276 kPa (40 psia) at 37.8° C (100° F).

In-plant piping system means piping that is located on the grounds of a plant and used to transfer hazardous liquid or carbon dioxide between plant facilities or between plant facilities and a pipeline or other mode of transportation, not including any device and associated piping that are necessary to control pressure in the pipeline under §195.406(b).

Interstate pipeline means a pipeline or that part of a pipeline that is used in the transportation of hazardous liquids or carbon dioxide in interstate or foreign commerce.

Intrastate pipeline means a pipeline or that part of a pipeline to which this part applies that is not an interstate pipeline.

Line section means a continuous run of pipe between adjacent pressure pump stations, between a pressure pump station and terminal or breakout tanks, between a pressure pump station and a block valve, or between adjacent block valves.

Low stress pipeline means a hazardous liquid pipeline that is operated in its entirety at a stress level of 20 percent or less of the specified minimum yield strength of the line pipe.

Maximum operating pressure (MOP) means the maximum pressure at which a pipeline or segment of a pipeline may be normally operated under this part.

Nominal wall thickness means the wall thickness listed in the pipe specifications.

Offshore means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

Operator means a person who owns or operates pipeline facilities.

Outer Continental Shelf means all submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.

Petroleum means crude oil, condensate, natural gasoline, natural gas liquids, and liquefied petroleum gas.

Petroleum product means flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds.

Pipe or *line pipe* means a tube, usually cylindrical, through which a hazardous liquid or carbon dioxide flows from one point to another.

Pipeline or *pipeline system* means all parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves, and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.

Pipeline facility means new and existing pipe, rights-of-way and any equipment, facility, or building used in the transportation of hazardous liquids or carbon dioxide.

Production facility means piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum or carbon dioxide, or associated storage or measurement. (To be a production facility under this definition, piping or equipment must be used in the process of extracting petroleum or carbon dioxide from the ground or from facilities where $CO_2$is produced, and preparing it for transportation by pipeline. This includes piping between treatment plants which extract carbon dioxide, and facilities utilized for the injection of carbon dioxide for recovery operations.)

Rural area means outside the limits of any incorporated or unincorpated city, town, village, or any other designated residential or commercial area such as a subdivision, a business or shopping center, or community development.

Specified minimum yield strength means the minimum yield strength, expressed in p.s.i. (kPa) gage, prescribed by the specification under which the material is purchased from the manufacturer.

Stress level means the level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength.

Surge pressure means pressure produced by a change in velocity of the moving stream that results from shutting down a pump station or pumping unit, closure of a valve, or any other blockage of the moving stream.

Toxic product means "poisonous material" as defined by §173.132 Class 6, Division 6.1–Definitions of this chapter.

Unusually Sensitive Area (USA) means a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release, as identified under §195.6.