Preliminary Regulatory Impact Analyses

Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines

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

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Executive Summary

The Pipeline and Hazardous Materials Safety Administration (PHMSA) proposes to amend the Federal Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement Integrity Management Programs (IMPs). The purpose of these programs is to enhance safety by identifying and reducing pipeline integrity risks. Societal costs associated with hazards and incidents related to gas distribution systems addressed by the rule are approximately $1 billion per year. If these changes are implemented, there will be benefits due to a reduction in deaths, injuries, and property damages associated with gas distribution systems.

This rule proposes IMPs similar to those required for gas transmission pipelines, but tailored to reflect the differences in and among distribution systems. PHMSA proposes to require operators of gas distribution pipelines to develop and implement IMPs that will better assure the integrity of their pipeline systems. Each IMP must contain the following elements:

- Improving knowledge of the system's infrastructure
- Identifying threats (existing and potential)
- Evaluating and prioritizing risks
- Identifying and implementing measures to mitigate risks
- Measuring performance, monitoring results, and evaluating effectiveness
- Periodic re-evaluation and improvement
- Reporting results

All of the above elements pertain to distribution operators with the exception of master meter and liquid petroleum gas (LPG) distribution systems. To minimize regulatory burdens, the proposed rule establishes simpler requirements for master meter and LPG operators, reflecting the relatively lower risk posed by these small pipeline systems. This proposal also addresses statutory mandates and recommendations from the Department of Transportation's (DOT) Office of the Inspector General (OIG) and stakeholder groups.

These analyses find that the proposed rule is not expected to adversely affect the economy or the environment. The analysis finds that, for those costs and benefits that can be quantified, the present value of net benefits are expected to be between $1.5 billion and $2.8 billion over a 50-year period after all of the requirements are implemented. Furthermore, the proposed rule is expected to be cost-effective if it results in eliminating only approximately 14.5 percent of the societal costs associated with gas distribution systems. The estimated monetary cost of the rule is $155 in the first year and about $104 million per year after the first year, while the estimated monetary benefits are $214 million per year. Therefore, DOT has classified this rulemaking as an economically significant regulatory action under Section 3(f)(1) of Executive Order 12866, and a significant regulatory action under the DOT's regulatory policies and procedures (44 FR 11034). There is substantial congressional, industry, and public interest in the rule. The proposed rule will serve to standardize industry practices, so that all pipelines operate under the same uniform standard.

Based on this analysis, PHMSA has also determined that the proposed rule would impose expenditures in excess of $132 million on State, local, or tribal governments or the private sector in the first year.

PHMSA has also estimated, as required by the Regulatory Flexibility Act (RFA), that the proposed rule would have an impact on a substantial number of small entities in the United States. PHMSA estimates that 1,007 local gas distribution utilities and 8,000 master meter operators will be impacted by the proposed rule. PHMSA cannot estimate what percent of revenues the costs of the proposed rule represent, since the Agency does not have information on operators' revenues. The costs associated with the proposed rule may be significant for at least some of the small entities. Therefore, PHMSA assumes that the proposed rule could result in a significant adverse economic impact for some of the smallest affected entities. PHMSA invites comments on these assumptions. We have included a Regulatory Flexibility Analysis which discusses these issues.

1. INTRODUCTION

The Pipeline and Hazardous Materials Safety Administration (PHMSA) has issued Integrity Management Program (IMP) regulations for operators of hazardous liquid pipelines (49 CFR 195) and gas transmission pipelines (49 CFR Part 192, Subpart O). Those regulations require operators to continually assess, evaluate, repair, and validate through comprehensive analysis, the integrity of pipeline segments and take actions to address applicable threats and integrity concerns. Similar regulations do not currently exist for gas distribution pipelines.

PHMSA proposes to revise the Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement programs that will better assure the integrity of their pipeline systems. The proposed regulations require distribution pipeline operators to implement an IMP similar to those required for gas transmission pipelines. The proposed regulation requires that the IMPs contain the following elements:

a) *Improving knowledge of the system's infrastructure*. An operator's integrity management program must demonstrate the operator understands its gas distribution system including factors such as: location, material composition, piping sizes, construction methods, date of installation, soil conditions, pressure (operating and design), operating experience, performance data, condition of the system, and any other characteristics important to a thorough understanding of applicable threats and their contribution to risks.
b) *Identifying threats (existing and potential).* The operator must identify existing and potential threats that apply to its pipeline. The operator must consider, at minimum, the following categories of threats to each gas distribution pipeline: corrosion, natural forces, excavation damage, other outside force damage, material or welds, equipment, operations, and any other concerns that may threaten the integrity of the pipeline.
c) *Evaluating and prioritizing risk.* An operator must evaluate the risk associated with its distribution pipeline system. This evaluation must consider each of the applicable existing and potential threats.
d) *Identifying and implementing measures to mitigate risks.* An operator must determine and implement measures designed to reduce the risk of each identified threat.
e) *Measuring performance, monitoring results, and evaluating effectiveness.* An operator must develop and monitor performance measures, from an established baseline, to evaluate the effectiveness of its integrity management program.
f) *Continual re-evaluation and improvement.* The operator must re-evaluate threats and risks periodically.
g) *Reporting results.* The operator must report annually to PHMSA some of the performance measurements resulting from the element: *Measuring performance, monitoring results, and evaluating effectiveness.*

All of the above elements pertain to distribution operators with the exception of master meter and liquified petroleum gas (LPG) distribution systems. For master meter and LPG systems the proposal would have their programs include all of the elements listed above except (1) evaluating and prioritizing risks and (2) reporting results.

In addition, the proposed rule requires the installation of excess flow valves (EFVs) on all new and renewed single family residential services operating at least 10 pounds per square inch gauge (psig), as long as certain operating conditions are met. Master meter and LPG systems would be exempt from this requirement. The proposed mandatory installation renders the current customer EFV notification requirement (see 49 CFR 192.383) moot. Consequently, the proposed rule would repeal that requirement.

Incidents and accidents associated with gas distribution pipeline systems result on average every year in over 10 fatalities, over 40 serious injuries, and tens of millions of dollars of property damages. Also, each year hundreds of millions of dollars of gas is lost due to leaks in the system. The purpose of this regulation is to address the hazards that lead to those incidents as well as reduce gas loss by including leak management, damage prevention, and excess flow valve provisions. In this report, the benefits and costs of the proposed regulatory changes are examined, as required by EO 12866 and the Unfunded Mandates Reform Act. Additionally, the report includes the analysis required by the Regulatory Flexibility Act.

2. BACKGROUND

The Nation's existing pipeline infrastructure, much of which is over 50 years old, requires regular safety and environmental reviews to ensure its reliability and integrity. To improve safety and to address several statutory mandates and National Transportation Safety Board (NTSB) recommendations, PHMSA established Integrity Management requirements in years 2000 and 2002, for operators of hazardous liquid pipelines (49 CFR 195.452).

Subsequently, PHMSA issued IMP regulations for gas transmission pipelines in December 2003 (49 CFR Part 192, Subpart O). Both the hazardous liquid and gas transmission pipeline IMP regulations require operators to analyze risks and focus increased attention on safety, especially the portions of their pipeline that pose the highest risk. This increased attention must include physical inspection (assessment) of the pipe using in-line inspection, pressure testing, or direct assessment, remediation of anomalous conditions following the assessment, continual evaluation of the pipeline, application of additional preventive and mitigative measures, and development of performance measures.

Current IMP regulations, however, do not apply to gas distribution pipelines. Gas distribution pipelines deliver gas to residences and other end users and are different from hazardous liquid and gas transmission pipelines. Distribution systems are comprised of a grid of "mains" and "service lines." A main is a pipeline that serves as a common source of supply for multiple customers, often located under municipal streets that may be in heavily populated or congested areas. Service lines transport gas from the mains to the meters or customer-owned piping of residential, commercial, and industrial customers. Distribution pipelines can measure as large as 36 inches in diameter; however, most are much smaller, ranging in size from one-half inch service lines to 8 inches in diameter for mains. These pipelines generally operate at lower pressures than the transmission pipelines and are owned and operated by local distribution companies. Distribution pipelines are constructed of a variety of materials, both metallic and non-metallic. Approximately half of the pipe in distribution systems is plastic. To reach the many end users they serve, distribution pipelines include extensive branching and interconnection, which is significantly different from the long, uninterrupted runs of transmission system pipe. These differences make it impractical to simply apply gas transmission integrity management requirements to distribution pipelines and instead necessitate integrity management program requirements tailored to distribution pipelines.

3. REGULATORY ANALYSIS

Executive Order 12866 directs all Federal agencies to consider the costs and benefits of "significant regulatory actions." Of these, Federal agencies are directed to develop a formal Regulatory Impact Analysis consistent with OMB Circular A-4 for all "economically significant" rules, or those rules estimated to have an impact on the economy of $100 million or more in any one year. The Order also requires a determination as to whether a rule could adversely affect the economy or a section of the economy in terms of productivity and employment, the environment, public health, safety, or State, local or tribal governments. This requirement applies to rulemakings that rescind or modify existing rules as well as to those that establish new requirements. The goal of the analysis is to provide decision makers with a clear indication of the most efficient alternative—that is, the alternative that generates the largest net benefits to society (ignoring distributional effects).

This regulatory analysis:

1) Identifies the target problem, including a statement of the need for the proposed action.
2) Identifies available alternative approaches.
3) Defines the baseline.
4) Defines the scope and parameters of the analysis.
5) Defines and evaluates the costs and benefits of the proposed action and the main alternatives identified by the analysis.
6) Compares the costs and benefits.
7) Interprets the cost and benefit results.

4. IDENTIFICATION OF THE PROBLEM AND THE NEED FOR THE RULE

There are several reasons why this Federal regulation is being proposed. The gas distribution system is a diverse industry. The Integrity Management for Gas Phase I Report written by a multi- stockholder group (which was created to study integrity management on behalf of the Agency) noted "It is important to recognize the wide diversity that exists among distribution pipeline operators. Some operators are very large, serving more than one million customers."[1] The industry is composed of: some very small operators, such as master meter operators, serving only a few customers; medium sized operators, the majority of which are municipal agencies, serving from 100 and 10,000 diverse customers; and large pipeline systems. In areas where gas service has been available for many years there are thousands of miles of pipeline of various materials and ages. Newer systems can be more uniform, consisting of one or a few types of pipe with similar fittings and connections installed using uniform procedures.

The gas distribution system that serves local markets does not fit a competitive market model. The pipeline infrastructure is installed so that the local operator that delivers that product has somewhat of a natural monopoly. Research on this specific industry has indicated that there are no robust market signals or incentives to prompt operators to thoroughly assess the condition of their pipelines or to implement integrity management programs. For example, the Government Accounting Office (GAO) has pointed out in a study of gas transmission operators[2] that the gas transmission integrity management program prompted some operators to make assessments of their pipelines for the first time. We believe the market structure of the distribution industry has similarly led to distribution system operators spending a less than socially optimal amount of resources and attention to pipeline integrity.

Operators may also have inadequate information to assess the risks associated with gas distribution systems, because they may not have observed incidents involving death or serious injury in any given year (or decade, for that matter), and smaller operators are even less likely to see such incidents. Even though an incident in a particular pipeline is a low probability event, the risk is still inherent in the system itself, and consequences of an incident can be severe. In fact, about half of all reported incidents from distribution operators involve death or major injury— at a rate per mile that is roughly comparable to gas transmission pipeline systems. We believe, therefore, that the aggregate safety impacts on a national basis justify more significant investment in risk management systems.

Given this likely market failure, the rest of this analysis seeks to identify the most efficient particular approach to integrity management. PHMSA considered other means of dealing with market failure before proposing new, comprehensive requirements. PHMSA has examined the feasibility of regulating at the State level. Currently gas pipeline operators are subject to differing State regulations. PHMSA has determined that the diversity in State specific regulations dictates the need for Federal regulatory oversight. This is because many pipelines entities operate interstate. In these cases, we believe a cohesive nationwide regulatory policy better serves the public interests and

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[1] Integrity Management for Gas Distribution. Report of Phase I Investigations. December 2005. See http://www.cycla.com/opsiswc/docs/S8/P0068/DIMP_Phase1Report_Final.pdf, p.13.

[2] GAO, Gas Pipeline Safety, Preliminary Observations on the Integrity Management program and 7-Year Reassessment Requirement, GOO-06-474T, Testimony Before the Subcommittee on Highways, Transit and Pipelines, Committee on Transportation and Infrastructure, House of Representatives.

minimizes the cost of doing business in different States under diverse guidelines and regulations.

While intrastate gas systems are usually regulated by State pipeline safety agencies, Congress established a Federal interest in the regulation of these systems, and the Pipeline and Hazardous Materials Safety Administration supports these programs through Federal grants to States. Each State's program must be certified, or subject to an agreement with PHMSA to act on its behalf, as a condition for Federal funding.

PHMSA has concluded that a better understanding on the part of operators of the risks posed by their pipeline systems, and a better focus of their actions to address the most significant of those risks is the most effective way to improve the Nation's already-commendable pipeline safety record. Consequently, PHMSA has been implementing integrity management requirements on various pipeline types as part of its program to improve pipeline safety. The historical record shows, however, that more adverse safety consequences (75 to 80 percent of all pipeline incidents involving death or major injury) result from accidents on distribution pipelines than from those on the pipelines already subject to IMP requirements. It is not possible to produce a significant improvement in pipeline safety without addressing distribution pipelines. PHMSA has concluded, therefore, that it is appropriate to establish IMP requirements that will foster a similar understanding of and focus on risk among distribution pipeline operators.

In 2004, the DOT Inspector General (IG) pointed out recent accident trends for gas distribution pipelines were unfavorable and suggested the application of integrity management principles could help improve the safety of distribution pipelines. The IG acknowledged the reason distribution pipeline operators were exempt from the regulations was that distribution pipelines could not use the same inspection methods used for hazardous and transmission pipelines. Nevertheless, the IG concluded that there was no reason other elements of IMP could not be implemented for distribution pipelines.

The IG recommended to Congress[3] that DOT define an approach for requiring operators of distribution pipeline systems to implement some form of integrity management or enhanced safety program with elements similar to those required in hazardous liquid and transmission pipeline IMPs. The Appropriations Committee then asked PHMSA "to report to the House and Senate Committees on Appropriations by May 1, 2005, detailing the extent to which integrity management program elements may be applied to the natural gas distribution pipeline industry in order to enhance distribution system safety."[4] PHMSA submitted the report "Assuring the Integrity of Gas Distribution Pipeline Systems" to Congress in June 2005, describing the program used to identify opportunities for improving the safety of distribution pipeline systems.

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[3] "Progress and Challenges in Improving Pipeline Safety," Statement of the Honorable Kenneth M. Mead, Inspector General, Department of Transportation, before the Committee on Energy and Commerce, Subcommittee on Energy and Air Quality, U.S. House of Representatives, July 20, 2004.
[4] House of Representatives report 108-792, November 20, 2004.

PHMSA developed the program in two phases. Phase 1 identified the nature of requirements that might be imposed and any additional guidance or consensus standards that might be needed to assist operators in implementing any integrity management requirements. Phase 2 included development of appropriate requirements by PHMSA and preparation of guidance/standards by appropriate bodies. During the development of Phase 1, PHMSA involved a large number of key stakeholder groups including State and Federal regulators, representatives from the spectrum of distribution operators, interested members of the public, and representatives of the Nation's fire service. The stakeholders agreed with the DOT IG and Congress' recommendations and concluded that it would be appropriate to modify the regulations to include a risk-based integrity management process for gas distribution pipelines.[5]

5. IDENTIFICATION OF AVAILABLE ALTERNATIVE APPROACHES

PHMSA considered several alternatives to assure the necessary protection from potential incidents caused by gas distribution pipelines, with the intention of selecting the alternative that is likely to result in the highest net benefits. PHMSA considered the following approaches:

- Apply existing gas transmission pipeline IMP regulations to gas distribution pipelines.
- Model State legislation by imposing requirements on excavators and others outside the regulatory jurisdiction of pipeline safety authorities.
- Develop guidance documents for adoption by States.
- Implement prescriptive Federal regulations, specifying in detail, actions that must be taken to assure distribution pipeline integrity.
- Implement risk-based, flexible, performance-oriented Federal regulations, establishing high-level elements that must be included in integrity management programs.

After considering all the alternatives, PHMSA selected the following alternative: implementation of risk-based, flexible, performance-oriented Federal regulations establishing high-level elements that must be included in integrity management programs.

5.1 Baseline: No Action

This was used as the baseline against which PHMSA compared all other alternatives.

Regulatory analyses typically consider an alternative in which the agency would not take any action, because it would maintain the status quo. No new requirements would be levied. No costs would be incurred to implement new requirements. No new benefits would result.

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[5] "Integrity Management for Gas Distribution, Report of Phase 1 Investigations," prepared by Joint Work/Study Groups, December 2005, U.S. DOT/PHMSA - Report: DIMP Phase 1, Doc. Number: RSPA-2004-19854-70, available at http://dmses.dot.gov/docimages/p84/388302.pdf

In response to the mandate concerning IMPs for distribution systems contained in The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (Public Law No: 109-468, Dec. 29, 2006), also known as the PIPES Act, PHMSA is initiating this rulemaking. PHMSA is extending its integrity management approach to the largest segment of the Nation's pipeline network – the distribution systems that directly serve homes, schools, businesses, and other natural gas consumers. Beginning in 2000, the Agency promulgated regulations requiring operators of hazardous liquid pipelines (49 CFR 195.452, published at 65 FR 75378 and 67 FR 2136) and gas transmission pipelines (49 CFR 192, Subpart O, published at 68 FR 69778) to develop and follow individualized integrity management (IM) programs, in addition to PHMSA's core pipeline safety regulations. Although some pipeline operators are already implementing some elements of integrity management into their systems, the IMP approach was designed to promote continuous improvement in pipeline safety by requiring all operators to identify and invest in risk control measures beyond core regulatory requirements existing today.

By not taking action the Agency would be unresponsive to the congressional mandate in the PIPES Act and there would likely be no reductions in the numbers of deaths, injuries, or property damages associated with risks related to the integrity management of distribution lines. Although this alternative would not lead to increased compliance costs, there would be no reduction in the societal costs associated with the deaths, injuries, and property damages associated with integrity management improvements. This alternative results in zero net benefits. Thus, this alternative is the baseline for comparison with other alternatives.

5.2 Apply existing gas transmission pipeline IMP regulations to gas distribution pipelines

This alternative was determined by PHMSA to be infeasible.

Gas distribution pipelines are different from hazardous liquid and gas transmission pipelines. Distribution systems combine main lines with an almost equal amount of mileage branching from the main lines to connect services to natural gas users. Lines are generally smaller in diameter, operate at much lower pressures, and are constructed of a variety of materials, both metallic and non-metallic. Approximately half of the pipe in distribution systems is plastic compared to very small amounts of plastic gas transmission pipeline. To reach the many end users they serve, distribution pipelines include extensive branching and interconnection compared to transmission systems that have long uninterrupted runs of pipe. These differences substantially distinguish distribution systems from transmission systems and thus it is not technically feasible to apply gas transmission integrity management requirements to distribution pipelines. For instance, the low pressures, small diameters, and complex connections associated with distribution systems make it infeasible to use smart pigs or hydrotesting, techniques that are used by transmission lines for integrity management. Since we have determined this alternative is not technically feasible to implement, we were unable to estimate impacts. Consequently, no further consideration was given to this alternative.

5.3 Model State legislation, potentially imposing requirements on excavators and others outside the jurisdiction of pipeline safety authorities

This alternative was determined by PHMSA to be infeasible because PHMSA could not ensure that any or all of the States adopt the model State legislation.

According to the Integrity Management for Gas Distribution Report of Phase I Investigations, experience indicates that this option may not be practical for addressing the broad question of integrity management. The group references the failure of State legislatures to adopt an available model from the Common Ground effort to prevent excavation damage.[6]

In studying the issue, the study group found that model State legislation may be useful for narrower issues, such as improving excavation damage prevention through implementation of comprehensive damage prevention programs, including active enforcement.[7] The report concludes, "There are many factors affecting State approaches to regulation. It would be very unlikely that all States could adopt model legislation with sufficient consistency that would represent a national solution to integrity management concerns."

After careful study, this option is not considered any further as a means of addressing the entire integrity management issue because the integrity management study group found that the issues surrounding integrity management are broad and require a holistic approach at the Federal level. Not being operationally feasible, this alternative was not considered to be amenable to a comparison of the costs and benefits.

5.4 Guidance documents for adoption by States with the intent of States mandating use of the guidance

As with the previous alternative, this alternative was determined by PHMSA to be infeasible because PHMSA could not ensure that any of the States would mandate the use of the guidance therefore distribution safety would not improve.

The Integrity Management for Gas Distribution Report of Phase I Investigations determined that this option is essentially the same as option 5.3 above, except it contemplates States adopting the guidance as mandatory requirements. As with model legislation, the study group considered that adoption likely would not occur in many States. Although the Federal government establishes basic safety standards, integrity management certified States are responsible for intrastate pipelines. The study group notes that States typically have not uniformly adopt recommended approaches in the past. Selecting this option would thus provide only the illusion of a solution. The costs of such an approach would be relatively low, but if the conclusions of the study group are correct,

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[6] The group was composed of representatives of the natural gas distribution industry, state pipeline regulatory authorities and the public. See http://www.cycla.com/opsiswc/docs/S8/P0068/DIMP_Phase1Report_Final.pdf, p.71.

[7] See http://www.cycla.com/opsiswc/docs/S8/P0068/DIMP_Phase1Report_Final.pdf, p.71.

there would also be low benefits and perhaps, insignificant net benefits. For these reasons, this alternative was not considered any further.

5.5 Prescriptive Federal regulation, specifying in detail actions that must be taken to assure distribution pipeline integrity

This alternative was determined by PHMSA to be too inflexible to be applicable to all relevant situations that distribution system operators might face.

The Integrity Management for Gas Distribution Report of Phase I Investigations report reaffirms the need for a flexible Federal rule. The study group reasoned that a highly detailed prescriptive regulation would eliminate the flexibility needed to address the unique circumstances of individual States and operators. The study group reported, "The issues important to assuring the integrity of these diverse systems will vary. This diversity makes it difficult for any one prescriptive requirement to address all possible circumstances. It is important that any new requirements that are developed allow sufficient flexibility for the operators of distribution pipeline systems, and the State regulators who oversee their operations, to customize their integrity management efforts to address their specific systems, threats, and issues."[8]

Although some small operators might prefer a prescriptive regulation, most large operators want the flexibility of a performance-based regulation. The wide range in size and nature of distribution pipeline systems calls for a flexible approach to integrity management rather than a single detailed set of requirements. Giving operators the guidance and allowing them to shape it to fit their particular system will assure integrity management efficiently and effectively. A detailed prescriptive rule was deemed by PHMSA to be too inflexible to be applicable to all relevant situations that distribution operators might face, since there is wide spectrum of distribution operators, from Master meter (mostly one-man operation) to large utilities covering thousand of miles of pipelines and over a million customers. Thus a prescriptive rule would be inappropriate and ineffective, resulting in many operators being required to perform tasks not appropriate for their pipeline systems. [9] These statements of the rule being ineffective and inappropriate suggest that there would likely be a low level of net benefits. For these reasons a prescriptive Federal regulation was evaluated no further.

5.6 Risk-based, flexible, performance-oriented Federal regulation, establishing high-level elements that must be included in integrity management programs

This alternative was determined by PHMSA to be practicable and is compared in this document with the baseline "no action" alternative. As will be demonstrated, there are significant net benefits associated with this alternative.

[8] Integrity management for Gas Distribution. Report of Phase I Investigations. December 2005. See http://www.cycla.com/opsiswc/docs/S8/P0068/DIMP_Phase1Report_Final.pdf, p.13-14.
[9] See http://www.cycla.com/opsiswc/docs/S8/P0068/DIMP_Phase1Report_Final.pdf, p.72

This alternative, that is the subject of the proposal, creates a high-level, flexible, and performance-based Federal regulation that requires gas distribution operators to develop and implement an integrity management program for their distribution pipeline systems. The proposed regulation requires all operators of a distribution pipeline system to implement an integrity management program and would prescribe minimum requirements each operator must meet in doing so. An integrity management program is intended to manage the risks associated with an operator's pipeline system.

An integrity management program would include, at a minimum, the following elements:

- Improving knowledge of the system's infrastructure
- Identifying threats (existing and potential)
- Evaluating and prioritizing risk
- Identifying and implementing measures to mitigate risks
- Measuring performance, monitoring results, and evaluating effectiveness
- Periodic re-evaluation and improvement
- Reporting results

This alternative also embraces the installation of excess flow valves (EFVs). An operator (excluding LPG and master meter operators) would be required to install an EFV on newly-installed or replaced service lines that operate continuously throughout the year at a pressure not less than 10 psig and serve a single-family residence, unless doing so would not be practicable. This requirement applies only to new or replaced service lines. There is no requirement for an operator to install an EFV retroactively on an existing service. The PIPES Act 2006 mandated this requirement.

The requirement on EFVs is intended to replace the notification requirements in 49 CFR 192.383, which requires operators to notify the customer for new and replaced service lines about the availability and benefits derived for installing an EFV. PHMSA believes the customer notification requirement would not be necessary if the proposed rule goes into effect.

Federal pipeline safety law requires States adopt requirements at least as stringent as those established by PHMSA to maintain their certification to exercise regulatory jurisdiction over intrastate pipeline safety. This alternative establishes basic requirements, while allowing States the flexibility to accommodate the unique needs of different geographical areas and different communities of operators. Furthermore, the alternative does this while assuring that a Federal rule, which provides for a consistent approach to distribution integrity management, is implemented. For the reasons stated above, this alternative was selected.

In order to implement the IMP regulations, PHMSA proposes to add a new *Subpart P – Gas Distribution Pipeline Integrity Management* to 49 U.S.C., Part 192 as follows:

- 192.1001 What do the regulations in this subpart cover?
- 192.1003 What definitions apply to this subpart?

- 192.1005 What must an operator do to implement this subpart?
- 192.1007 What are the required program elements?
- 192.1009 When must an Excess Flow Valve (EFV) be installed?
- 192.1011 Where does an operator file a report?
- 192.1013 What records must an operator keep?

Note, under the proposal, master meter or LPG operators of gas distribution pipelines would comply only with the requirements in Sections 192.1005 and 192.1007, with some exceptions under 192.1007, such as prioritizing risks and reporting results. This is due to the simple nature of their systems.

6. INDUSTRY INFORMATION

6.1 Impacted Operators and Mileage

The proposed regulatory changes will apply to all operators of gas distribution systems, including master meter and LPG systems regulated under 49 CFR Part 192. Master meter and LPG system operators, however, will only need to meet some of the requirements applicable to other operators.

For this analysis, gas distribution systems will be divided into three categories:

(1) Gas distribution systems with over 12,000 services that are operated by local gas distribution companies (i.e., local gas utilities).
(2) Gas distribution systems with 12,000 or fewer services that are operated by local gas utilities.
(3) Master meter and LPG systems.

Each category will be affected somewhat differently by the proposed rule. In particular, the costs that each of the operators in each category will face are expected to be different.

The first category covers the largest local gas utilities impacted by the proposed rule. Industry sources report that, for management and operational purposes, local gas utilities begin to break their systems into districts when they have more than 12,000 services. As of 2004, there were 201 operators in this category.

The second category covers the smaller local gas utilities impacted by the proposed rule. This category does not include the master meter and LPG systems impacted by the proposed rule, since local gas utilities do not generally operate these systems. As of 2004, there were 1,090 operators in this category.

The third category covers the master meter and LPG systems impacted by the proposed rule. These are generally very small gas distribution systems. The number of these systems is unknown, but, for this analysis, PHMSA estimates that approximately 8,000 of these systems would be impacted by the proposed rule. This estimate is based on reports to PHMSA in 2004 from (1) 45 State pipeline safety agencies indicating that, collectively, 6,972 master meter systems were operating in their States and (2) 35 State pipeline safety agencies indicating that, collectively, 926 LPG systems were operating in their States. Because identifying master meter systems is often difficult and because some State pipeline safety regulators do not have jurisdiction over all master meter systems in their States, PHMSA believes that the number of master meter systems reported by the States actually understates the number currently subject to Federal pipeline safety regulation.

Table 2 presents the numbers of systems, distribution main mileage, and services that will be used in this analysis. The numbers for the large and small local distribution systems are based on the situation in 2004. The estimated number of master meter and LPG systems is discussed above. The estimate for master meter and LPG distribution main mileage assumes that each operator has, on average, one mile of distribution mains. The estimate for master meter and LPG services assumes that each operator has, on average, 100 services.[10]

[10] Information on the number of services and pipe length for master meter systems is limited. According to PHMSA, "Assessment of the need for an improved inspection program for Master Meter Systems," January 2002, p. 7, at http://ops.dot.gov/pubs/Mastermeter.pdf, the average number of customers of master meter systems in Maryland was reported to be 284, while 7 of the 8 master meter systems known to be operating in Nevada were reported to have from 100 to 275 customers, and the average length of underground or exterior piping at master meter systems in Maryland was reported to be 2,764 feet (this includes both mains and services).

TABLE 1. NUMBER OF SYSTEMS, DISTRIBUTION MAIN MILEAGE, AND NUMBER OF SERVICES IMPACTED BY THE PROPOSED DISTRIBUTION INTEGRITY MANAGAMENT PROGRAM (DIMP) REQUIREMENTS

Characteristic	Number
Large Local Distribution Systems	
Number of systems	201
Distribution main mileage	1,010,000 miles
Number of services	54,900,000
Small Local Distribution Systems	
Number of systems	1,090
Distribution main mileage	120,000 miles
Number of services	5,270,000
Master Meter and LPG Systems	
Estimated number of systems	8,000
Distribution main mileage	8,000 miles
Number of services	800,000
Total	
Estimated number of systems	9,291
Distribution main mileage	1,138,000 miles
Number of services	60,970,000

Sources: Large and small local distribution systems—2004 data submitted to PHSMA; Master meter and LPG systems—PHMSA estimate of number of systems based on information from State pipeline safety agencies submitted to PHMSA in 2004. For this analysis, PHMSA assumes that every master meter and LPG system has, on average, one mile of distribution main and 100 services.

As Table 1 indicates, PHMSA expects the proposed rule to impact 9,291 operators with a combined total of 1,138,000 miles of distribution mains and 60,970,000 services. Furthermore, assuming that each service is, on average, 65 feet in length,[11] the total pipeline mileage impacted by the proposed rule would be 1,888,578 (= 1,138,000 + (60,970,000 x 65) / 5280 feet per mile).

PHMSA encourages industry comment on the estimates presented in this section.

7. DEFINITION AND EVALUATION OF THE BENEFITS AND COSTS OF THE PROPOSED ACTION

The impact of the proposed regulatory change consists of the benefits and costs attributable to that change. Table 2 presents a list of the benefits and costs considered in this analysis.[12]

[11] This is the current estimate used by PHMSA for the length of a service.
[12] All monetary values, unless otherwise indicated, are in 2008 constant dollars.

TABLE 2. BENEFITS AND COSTS CONSIDERED IN THIS ANALYSIS

Benefits	Costs
• Reductions in the consequences of reportable incidents • Reductions in the consequences of non-reportable incidents • A reduction in the probability of a major catastrophic incident • Reductions in lost natural gas • Reductions in emergency response costs • Reductions in evacuations • Reductions in dig-ins impacting non-gas underground facilities • The end of the existing EFV notification requirement	• Development of an IMP • Implementation of the IMP (data acquisition and analysis) • Mitigation of risks • Reporting to PHMSA and State Regulators • Recordkeeping • Management of the IMP

7.1 Benefits

The proposed rule mandates the design and implementation of integrity management programs on natural gas distribution systems. Integrity management programs are designed to proactively address problems related to corrosion, damage by outside forces, pipeline defects, and pipeline equipment and operations. The benefits resulting from the proposed rule are expected to result from the correction of problems that could cause pipeline failures before those failures occur, thereby averting pipeline accidents.

Natural gas incidents can have significant impacts. The consequences of natural gas distribution system accidents include deaths, injuries, and property damage. Recent examples of distribution pipeline incidents include the following: On December 13, 2005, at 9:26 a.m., an apartment building exploded in Bergenfield, New Jersey, after natural gas migrated into the building from a damaged pipeline. Investigators found a break in an underground 1 1/4-inch steel natural gas distribution service line that was operating at 11 1/2 pounds psig. There were three fatalities and five injuries. Damage was estimated at $863,300. On August 21, 2004, a natural gas explosion destroyed a residence in DuBois, Pennsylvania. A leaking butt-fusion joint in a 2-inch-diameter plastic main line pipe was the cause of the accident. Two residents were killed in this accident. Damage was estimated at $800,000.[13]

To run a safe pipeline, operators must have adequate information, the ability to anticipate problems, and the means to ensure the pipeline integrity. Positive benefits are expected from the proposed rule. Reduced numbers of deaths and injuries and reduced property damage are expected to be important benefits of the proposed rule.

[13] NTSB reports. See http://www.ntsb.gov/publictn/2007/PAB0701.htm

The proposed rule is expected to reduce the consequences of future accidents through identification and remediation of problems before those problems can result in accidents. The proposed rule will not eliminate all gas distribution system accidents. Estimates will need to be developed for the proportion eliminated, and where that is not practicable, assumptions will need to be made. In some cases, it will not be possible to quantify the benefits. In those cases, a qualitative discussion of the benefits will be presented.

Each of these benefits is addressed below. Following the discussions of these benefits, the estimated total benefits for the proposed rule will be calculated and then used to estimate the present value of the proposed rule over 50 years.

7.1.1 Benefits Resulting from a Reduction in the Consequences of Reportable Incidents

From 2001 through 2005, PHMSA received reports on 711 natural gas distribution system incidents. Those incidents resulted in 58 deaths, 227 injuries requiring hospitalization, and approximately $594 million in property damage (in nominal, not constant dollars). The breakdown of incidents and consequences by year for 2001 through 2005, along with the estimated pipeline mileage for those years, is presented in Table 3.

TABLE 3. REPORTED DISTRIBUTION SYSTEM INCIDENTS, 2001-2005[14]

Year	Incidents	Deaths	Injuries	Property Damage (Nominal Dollars)	Estimated Pipeline Miles (Mains plus Services)
2001	124	5	46	$14,071,486	1,837,277
2002	102	10	44	$23,804,202	1,855,319
2003	141	11	58	$21,032,408	1,865,679
2004	174	18	41	$37,507,950	1,918,270
2005	170	14	38	$497,696,278	1,823,136

Most of the $498 million (nominal dollars) in property damage for 2005 is attributable to the devastation caused by Hurricane Katrina. It should be noted that Table 3 does not include information attributable to incidents on master meter systems, since these operators are not required to report their incidents to PHMSA.[15] However, based on a 2002 DOT Report to Congress, from 1995 to 1999, there were two master meter system incidents, which resulted in two injuries and $200,000 in damages. One incident resulted from corrosion and the other from construction/operation error.[16]

[14] Source: http://ops.dot.gov/stats/stats.htm.
[15] See 49 CFR 191.9.
[16] Assessment of the Need for an Improved Inspection Program for Master Meter Systems, A Report of the Secretary of Transportation to the Congress, prepared pursuant to Section 108 of Public Law 100-561, p.17

Benefits Resulting from Reportable Non-Excavation Incidents

From 2001 through 2005, PHMSA received reports on 409 non-excavation incidents occurring on natural gas distribution systems. Those incidents resulted in 46 deaths, 149 injuries requiring hospitalization, and approximately $547 million in property damage (in nominal, not constant dollars). The breakdown of incidents and consequences by year for 2001 through 2005, along with the estimated pipeline mileage for those years, is presented in Table 4.

TABLE 4. REPORTED NON-EXCAVATION INCIDENTS ON GAS DISTRIBUTION SYSTEMS, 2001-2005[17]

Year	Incidents	Deaths	Injuries	Property Damage (Nominal Dollars)	Estimated Pipeline Miles (Mains plus Services)
2001	59	2	27	$6,922,115	1,837,277
2002	65	8	36	$14,138,500	1,855,319
2003	68	7	21	$10,488,683	1,865,679
2004	113	17	35	$26,543,229	1,918,270
2005	104	12	30	$488,913,297	1,823,136

.

Based on the information in Table 4, from 2001 through 2005, gas distribution systems experienced the following due to non-excavation incidents:

- 43.8 incidents per million miles per year,
- 4.9 deaths per million miles per year,
- 15.9 injuries requiring hospitalization per million miles per year, and
- $61,892,587 (2006 dollars) of property damage per million miles per year.

In order to develop an estimate of the expected benefits of this proposed rule, PHMSA makes two adjustments to the raw expected values of deaths, injuries, and property damage based on results from 2001-2005. The first such adjustment is explained here, and serves to lower the expected value of damages: because of the devastation attributable to Hurricane Katrina, the property damage in 2005 was at least an order of magnitude greater than the property damage in any year from 1986 through 2004. As a consequence, PHMSA considers the property damage in 2005 to be an extreme outlier that is unlikely to reoccur in the near future. Furthermore, the focus of this analysis is integrity management, and PHMSA notes that integrity management is unlikely to have much impact on incidents resulting from extreme hurricane damage.

The property damage from 2001 through 2004 would appear to be more representative of the property damage generally experienced by gas distribution systems in recent years

[17] Source: http://ops.dot.gov/stats/stats.htm.

than the property damage from 2001 through 2005. From 2001 through 2004, PHMSA estimates that gas distribution systems experienced:

- $8,356,808 (2006 dollars) in property damage per million miles per year.

For this analysis, PHMSA assumes that incident consequences in the future will mirror those of the recent past (although due to the short duration of the consequence measured here, PHMSA makes an adjustment to this assumption in the section below). Specifically, with the exception of property damage, PHMSA assumes that the average figures developed from Table 4 for 2001 through 2005 will be representative of the future for non-excavation incidents. For property damage, PHMSA assumes that the average figure developed from Table 4 for 2001 through 2004 will be representative of the future for those incidents.

The Department of Transportation currently makes the following assumptions concerning the value of a statistical life and the value of an injury requiring hospitalization:

- The value of a statistical life is $5,800,000.[18]
- Injuries requiring hospitalization are valued at $562,500.[19]

Multiplying the values for a statistical life and injuries requiring hospitalization by PHMSA's estimates for deaths and injuries puts those estimates into monetary terms. Multiplying those results, as well as the estimate for property damage, by the total mileage for the impacted pipeline yields estimates of the expected annual cost to society attributable to the deaths, injuries, and property damage resulting from non-excavation incidents on gas distribution systems.

Assuming the total impacted pipeline mileage is 1,888,578 miles, the expected annual cost to society attributable to deaths resulting from non-excavation incidents on gas distribution systems would be $53,998,000 (= 4.9 deaths per million miles per year x 1.9 million pipeline miles x $5,800,000), the expected annual cost to society attributable to injuries requiring hospitalization resulting from gas distribution system incidents would be $16,993,125 (=15.9 injuries per million miles per year x 1.9 million pipeline miles x $562,500), and the expected annual costs to society attributable to reported property damage resulting from gas distribution system incidents would be $15,877,935 (= $8,356,808 per million miles per year x 1.9 million pipeline miles). In total, the expected annual cost to society attributable to deaths, serious injuries, and property damage resulting from non-excavation incidents on gas distribution systems reported to PHMSA would be $86,869,060 (= $53,998,000 + $16,993,125 + $15,877,935).

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[18] On February 5, 2008, the Department issued a memorandum on the "Treatment of the Economic Value of a Statistical Life in the Departmental Analyses" directing DOT analysts to use $5.8 million as the best present estimate of the economic value of preventing human fatality. However the Department requested a supplementary analysis be conducted using values of $3.2 million and $8.4 million for each life saved.

[19] The average injury requiring hospitalization is assumed to be a "Severe injury," as defined by DOT. The cost to society of a "Severe injury" is assumed to be equal to 0.1875 times the cost to society of a lost life.

The reported deaths, serious injuries, and property damage that the proposed rule would prevent is unknown. The integrity management requirements for liquid pipelines and for gas transmission lines are not sufficiently similar to the proposed requirements for it to be reasonably expected that the reductions they experienced would be similar to those that distribution systems might experience. Furthermore, the integrity management activities of those pipelines have not been ongoing for long enough to ensure that the full benefits of those activities are now being achieved. Finally, it would be difficult to separate out those benefits from the benefits attributable to other regulatory actions undertaken by PHMSA.

PHMSA expects the impact of the integrity management activities contained in the proposed rule to be significant. For this analysis, PHMSA assumes that the proposed rule would prevent 50% of the reported deaths, serious injuries, and property damage.

Benefits Resulting from Reducing Reportable Excavation Incidents

From 2001 through 2005, PHMSA received reports on 302 excavation incidents occurring on natural gas distribution systems. Those incidents resulted in 12 deaths, 78 injuries requiring hospitalization, and approximately $47 million in property damage (in nominal, not constant dollars). The breakdown of incidents and consequences by year for 2001 through 2005, along with the estimated pipeline mileage for those years, is presented in Table 5.

TABLE 5. REPORTED EXCAVATION INCIDENTS ON GAS DISTRIBUTION SYSTEMS, 2001-2005[20]

Year	Incidents	Deaths	Injuries	Property Damage (Nominal Dollars)	Estimated Pipeline Miles (Mains plus Services)
2001	65	3	19	$7,149,371	1,837,277
2002	37	2	8	$9,665,702	1,855,319
2003	73	4	37	$10,543,725	1,865,679
2004	61	1	6	$10,964,721	1,918,270
2005	66	2	8	$8,782,981	1,823,136

Based on the information in Table 5, from 2001 through 2005, gas distribution systems experienced the following consequences due to excavation incidents:

- 32.4 incidents per million miles per year,
- 1.3 deaths per million miles per year,
- 8.4 injuries requiring hospitalization per million miles per year, and
- $5,460,750 (2006 dollars) of property damage per million miles per year.

[20] Source: http://ops.dot.gov/stats/stats.htm.

For this analysis, PHMSA assumes that future incident consequences will mirror those of the recent past. Specifically, PHMSA assumes that the average figures developed from Table 5 for 2001 through 2005 will be representative of the future for excavation-related incidents.

Multiplying the values for a statistical life and injuries requiring hospitalization that were presented earlier by PHMSA's estimates for deaths and injuries puts those estimates into monetary terms. Multiplying those results, as well as the estimate for property damage, by the total mileage for the impacted pipeline yields estimates of the expected annual cost to society attributable to the deaths, injuries, and property damage resulting from excavation incidents on gas distribution systems.

Assuming the total impacted pipeline mileage is 1,888,578 miles, the expected annual cost to society attributable to deaths resulting from excavation incidents on gas distribution systems would be $14,326,000 (= 1.3 deaths per million miles per year x 1.9 million pipeline miles x $5,800,000), the expected annual cost to society attributable to injuries requiring hospitalization resulting from gas distribution system incidents would be $8,977,500 (= 8.4 injuries per million miles per year x 1.9 million pipeline miles x $562,500), and the expected annual costs to society attributable to reported property damage resulting from gas distribution system incidents would be $10,375,425 (= $5,460,750 per million miles per year x 1.9 million pipeline miles). In total, the expected annual cost to society attributable to deaths, serious injuries, and property damage resulting from excavation incidents on gas distribution systems reported to PHMSA would be $33,678,925 (= $14,326,000 + $8,977,500 + $10,375,425).

For this analysis, PHMSA assumes that the actions included in the proposed rule will prevent 50% of the reported deaths, serious injuries, and property damage. Consequently, the benefits attributable to that reduction in consequences for reportable excavation incidents would be $16,839,463 (= $33,678,925 x 0.5) per year.

PHMSA assumes that 50% of the reduction in consequences for reportable incidents would result from the EFV requirements and 50% of the reduction would result from the enhanced damage prevention program requirements. Therefore, the annual benefits attributable to the enhanced damage prevention program requirements would be $8,419,731 (= $16,839,643 x 0.5) per year. The annual benefits attributable to the EFV requirements would also be an estimated $8,419,731.

Total Benefits Resulting from Reportable Incidents

The total benefits resulting from reportable incidents attributable to the proposed rule would be equal $60,273,993 per year, which is the sum of the benefits attributable to reportable non-excavation incidents, $43,434,530 per year, plus the benefits attributable to enhanced damage prevention programs, $8,419,731 per year, plus the benefits attributable to the EFV requirements, $8,419,731 per year.

7.1.2 Benefits Resulting from a Reduction in the Consequences of Non-Reportable Incidents

The proposed rule is expected to impact not only the number of reportable incidents and their consequences, but also the number of non-reportable incidents and their consequences, as well. The impact of the proposed regulatory changes on non-reportable incidents is unknown and must be estimated. To do this, it is necessary to estimate (1) the total number of federally non-reportable incidents, (2) the average cost of those incidents, and (3) the proportion or percentage of the federally non-reportable incidents that would be impacted by the proposed rule.

Estimate for the Total Number of Federally Non-Reportable Incidents

Section 122.2(d) of the California Public Utility Commission's General Order 112-E requires that pipeline operators submit quarterly reports to the Commission, and that those reports include information on:

- The gas leak incidents for which a telephonic report, a letter of explanation, or a DOT Form RSPA 7100.1 or 7100.2 were submitted.
- The gas leak incidents that involved escaping gas from an operator's facilities and property damage, including loss of gas, in excess of $1,000.
- All gas leak incidents that had property damage of between $0 and $1,000 involving fires, explosions, or excavation damage.

Table 6 presents the numbers of federally non-reportable gas distribution system incidents and their costs for 1998 through 2005 that were reported to the California Public Utility Commission under Section 122.2(d) of General Order 112-E.[21]

[21] General Order 112-E Rule 122.2 d requires utilities to submit quarterly reports to the Commission of all gas leaks that involved loss of gas or property damage in excess of $1,000, involving fire, explosion, or underground dig-ins.

TABLE 6. NON-REPORTABLE INCIDENTS IN CALIFORNIA, 1998-2005

Year	Number of Incidents	Aggregate Cost of Incidents – Loss of Gas and Property Damage (Nominal dollars)
1998	6,276	$3,003,388
1999	16,168	$5,314,328
2000	15,537	$6,093,456
2001	11,672	$3,585,534
2002	9,344	$2,667,416
2003	7,157	$2,054,593
2004	9,293	$2,229,366
2005	7,243	$1,226,032
TOTAL	**82,690**	**$26,174,113**

Source: Communication from the California Public Utility Commission, April 4, 2007.

Data related to federally reportable incidents is excluded from the numbers presented in Table 6.

From 1998 through 2005, California gas distribution systems reported 73 incidents to PHMSA.[22] This means that, for every incident reported to PHMSA, approximately 1,133 (= 82,690 / 73) non-reportable incidents occurred.

Of the 73 California gas distribution system incidents reported to PHMSA, 43 were caused by excavation damage.[23] Thus, the proportion of reportable incidents caused by excavation damage was 43/73. Assuming the proportion of non-reportable incidents caused by excavation damage is the same, approximately 668 (= 1,133 x 43/73) of the 1,133 incidents were caused by excavation damage. Furthermore, approximately 465 (= 1,133 - 668) of the 1,133 non-reportable incidents were not caused by excavation damage.

Based on the information in Table 3, the average number of reportable gas distribution system incidents that occurred from 2001 through 2005 was 142 (= ((124 + 102 + 141 + 174 + 170)/5). Multiplying this figure by those for non-reportable incidents per reportable incident yields estimates of the numbers of non-reportable incidents that might be expected annually in the U.S. in the future. Those estimates are (1) 66,030 (= 142 x 465) non-reportable incidents not involving excavation damage and (2) 94,856 (= 142 x 668) non-reportable incidents involving excavation damage. In total, there will be an estimated 160,886 (= 142 x 1,133) non-reportable incidents expected annually. These estimates do not include all non-reportable incidents that might occur, it must be recognized, but they do include those with the highest costs.

[22] Communication from PHMSA, April 11, 2007.
[23] Communication from PHMSA, April 11, 2007.

The Average Cost of Non-Reportable Incidents

As Table 6 indicates, the 82,690 federally non-reportable incidents reported to the State of California from 1998 through 2005 by gas distribution systems had a total cost of $26,174,113 (nominal). This is $317 (nominal) per incident (= $26,174,113 / 82,690). Converted to 2006 dollars, the cost becomes $361 per incident.

Based on California's non-reportable information, PHMSA assumes that the average cost of federally non-reportable incidents is $350.

The Proportion of Federally Non-Reportable Incidents Impacted by the Proposed Rule

The provisions included in the proposed rule cannot be expected to end all non-reportable incidents. The proportion that it will end is unknown. PHMSA assumes the provisions will reduce the consequences of non-reportable incidents by 50%. This is the same assumption made for reportable incidents. Additionally, PHMSA assumes that the benefits arising from incidents involving excavation damage can be split evenly between the EFV requirements and the enhanced damage prevention program requirements of the proposed rule. This also is the same assumption made for reportable incidents.

Impact of the Proposed Rule on Federally Non-Reportable Incidents

The proposed rule is expected to result in an annual reduction of $11,555,250 (= $350 x 66,030 x 0.5) in the costs of non-reportable incidents not involving excavation damage. Additionally, the proposed rule is expected to result in an annual reduction of $8,299,900 (= $350 x 49,856 x 0.5 x 0.5) in the costs of non-reportable incidents involving excavation damage due to enhanced damage prevention programs. The proposed rule is also expected to result in an annual reduction of $8,299,900 (= $350 x 49,856 x 0.5 x 0.5) in the costs of non-reportable incidents involving excavation damage due to its EFV provisions. In total, the proposed rule is expected to reduce the annual costs of non-reportable incidents by $28,155,050 (= $11,555,250 + $8,299,900 + $8,299,900).

7.1.3 Benefits of Avoiding an Accident with Low Probability and High Consequences

As mentioned above, PHMSA made an adjustment to the expected value of property damage because we believed the raw average 2001-2005 damages were skewed above expectations by the outlier of Hurricane Katrina, which posed a risk this proposed rulemaking was not designed to mitigate. We believe, however, that an additional adjustment to the raw 2001-2005 trends used to estimate consequences is warranted. A principal objective of pipeline safety regulation is to avoid accidents with adverse consequences. That this objective has been realized to a large degree is reflected in the fact that accidents with very severe consequences occur very rarely. As a consequence, the Agency believes that the 4-5 year baseline data is not reflective of the expected range of incidents mitigated by the proposed rule. The Agency believes that a more accurate expected value of benefits, perhaps reflective of a longer timeline and taking into account risks and consequences not experienced from 2001-2005, would show a higher expected benefit of this rule.[24] It is possible for high consequence accidents in which a disproportionately large number of casualties (i.e., deaths and serious injuries) to occur, since a portion of gas distribution piping is located in densely populated areas in which population densities are high and near schools and businesses that could house large number of people who might be affected by an accident.

For example, the largest accident that has occurred in U.S. distribution pipeline history occurred on November 21, 1996, in San Juan, Puerto Rico. A leak from an LPG line resulted in an explosion in a commercial building that killed 33 people and injured at least 69.[25] There is some disagreement as to whether the pipeline leak was a proximate cause or whether there was a fire first that then ignited the leaking propane. Nevertheless, this accident demonstrates that high-consequence events can occur as a result of gas line leaks.

To estimate the benefits derived from avoiding the consequences of high-consequence events, since that type of event clearly would fall outside most 4- to 5-year window and was not reflected in the baseline data, we use international data. The study completed recently by the Paul Scherer Institute (PSI) in Switzerland can be used as an indicator of the potential likelihood of a severe consequence of an event in the U.S.26 PSI's study was part of a comprehensive study of the safety of different energy systems. Although PSI concluded that natural gas has been demonstrably safer than other forms of energy, considering both transportation and use, it found that high-consequence accidents have occurred.

An accident occurred in Corlu, Turkey on August 9, 1992, in which 32 people were killed and 64 injured. The largest number of fatalities experienced as a result of a natural gas accident was found to have occurred in a 1995 accident in Taegu, Korea, in which 109 people were killed. Over the period analyzed (1969-2000), PSI found that 129 accidents occurred worldwide in which 5 or more persons were killed, resulting in 1,971 fatalities. During this period, 3 accidents involving more than 50 fatalities occurred within the countries comprising the Organization for Economic Development and Cooperation (OECD, which includes the U.S.). Six such accidents occurred in non-OECD countries.

[24] This assumption rests at least partly on a hypothesis that even if the short historical time series accurately reflects the expected probability of pipeline incidents, and even if that probability were expected to be normally distributed, the expected consequences of an event may not be normally distributed. In cases such as this, rare and extreme events would drive expected damages to a greater degree than their historical averages suggest. This addition to the analysis is intended to try and capture the influence of a rare, extreme event on future expected impacts. The Agency specifically requests comment on this addition to the analysis.

[25] NTSB Report Number PAR-97/01

[26] Peter Burgherr and Stefan Hirschberg, Comparative Assessment of Natural Gas Accident Risks, PSI Bericht Nr. 05-01, January 2005, available at http://gabe.web.psi.ch/pdfs/PSI_Report/SVGW_PSI-Bericht-05-01.pdf.

The PSI study considered the frequency of accidents with different numbers of consequences in order to develop an estimate of the probability of large-consequence accidents. The data were normalized to allow comparison of data from different countries. The basis for normalization was the electric energy equivalent of the amount of gas consumed, in gigawatts electric per year (GW_e-yr). The probability estimate took the form of a curve estimating the probability of an accident of a given number of fatalities per GW_e-yr. From this curve, the probability of an accident in which 45 persons are killed is estimated to be 0.0001 per GW_e-yr. PHMSA has used this probability in its analysis.

The PSI report did not estimate the number of serious injuries that would occur in addition to the number of fatalities. The limited experience described above demonstrates that more injuries than fatalities generally occur in these rare events. This mirrors the experience for events of lesser consequence. PHMSA has assumed, for purposes of this analysis, that 90 persons would be seriously injured in an event in which 45 persons were killed.

Applying this probability estimate to the U.S. for purposes of this analysis required that the electric equivalent of U.S. gas consumption be calculated. The Energy Information Administration reports that U.S. gas consumption in 2006 was 21,860,945 million cubic feet.[27] This amount was converted to an energy equivalent using a standard assumption of 35.6 megajoules per cubic meter (MJ/m^3). The resulting estimate of thermal energy used in the U.S. in 2006 in the form of natural gas is 2.2×10^{13} MJ. This thermal energy was then converted to electrical energy equivalent using an assumed efficiency factor of 0.35, the same factor used in the PSI study. The resulting estimate of electrical energy equivalent is 244.3 GW_e-yr.

This equivalent consumption amount was then multiplied by the probability per GW_e-yr inferred from the PSI study (1×10^{-4}). The resulting estimate of the probability of an accident in the U.S. that would involve 45 fatalities and 90 serious injuries is 0.0243 per year. That is, there is approximately a 2.5 percent chance in any given year that such an event would occur.

The number of such accidents that would be expected to occur in the U.S. in 50 years is thus 1.215. In twenty years, 0.486 events would be expected (i.e., there is a 48.6 percent chance of one event occurring in 20 years).

For analysis purposes, it is necessary to determine the monetary equivalent of the consequences of such an accident. Using the standard DOT assumptions for the value of a death and serious injury (described above), the consequences of one accident would be valued at $311.63 million.[28] Here, again, it would be unreasonable to assume that the

[27] EIA data from www.eia.doe.gov

[28] It is obvious that an accident of this magnitude would also result in significant consequences in terms of property damage. Such damage was not considered in the PSI study. The amount, although large, would likely be significantly less than the equivalent value of the deaths and injuries. For purposes of this analysis, PHMSA has conservatively ignored the contribution from property damage.

improvements to be realized as a result of this proposed rule will eliminate all possibility of a large-consequence accident. PHMSA does expect, though, that the efficacy of this proposal in avoiding a large-scale accident will be greater than that for avoiding smaller-scale incidents.

This is because the key elements of the DIMP programs that would be required by the proposed rule are for operators to analyze risks and to focus their risk avoidance activities on those areas where they can be most effective. Risk includes consideration of the likelihood of an event, as well as its consequences. Thus, areas where very high consequences could occur as a result of an accident will receive greater attention under operator DIMP programs than will portions of their systems subject to average or lower risk. PHMSA expects that this improved safety focus of DIMP activities will mean that this proposed rule will contribute at least 75% to avoiding a large-consequence accident of this nature. The consequences avoided are thus estimated to be $233.72 million per event. In a 50-year analysis horizon, the avoided consequences would total $283.97 million. Over a 20-year analysis, the avoided consequences would be $113.59 million. Put on an annual basis, the avoided consequences would be $5.71 million per year.

7.1.4 Benefits Attributable to Reducing Lost Gas

As a consequence of distribution system leaks, natural gas will be lost. Reducing the number of leaks through DIMP will reduce the quantity of natural gas that is lost.

The U.S. Environmental Protection Agency (EPA) estimates natural gas distribution system emissions of methane in 2005 at 1,303 gigagrams.[29] According to the EPA, those are "…mainly…fugitive emissions from gate stations and non-plastic piping (cast iron, steel)."[30] Some, of course, will also result from distribution system leaks in plastic piping. Assuming that (1) there are 0.052 billion cubic feet of methane per gigagram and (2) natural gas is 80% methane, the 1,303 gigagrams of methane emissions converts to 85 billion cubic feet (= 1,303 x 0.052 x 1/0.8) of natural gas. Assuming a city gate natural gas price of $8.67 per thousand cubic feet,[31] the total annual value of the lost gas given in 2005 dollars is approximately $737 million (= 85 billion cubic feet x $8.67). This becomes $759 million when converted to 2006 dollars.

PHMSA does not know the proportion of gas loss avoided by the implementation of DIMP, however for the purposes of this analysis is assumed to be 10 percent, or $76 million ($759 million* .10).

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[29] U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005," Public Review Draft, February 20, 2007, epa.gov/climatechange/emissions/downloads07/07Energy.pdf, pp. 3-46 to 3-47. A gigagram is a unit of weight equivalent to 10^9 grams.
[30] U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005," Public Review Draft, February 20, 2007, epa.gov/climatechange/emissions/downloads07/07Energy.pdf, p. 3-46.
[31] This was the average city gate price in 2005, according to Energy Information Administration, "Natural Gas Annual 2005," Nov. 16, 2006, www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_annual/current/pdf/table_022.pdf, p.53.

7.1.5 Benefits Resulting from Reduced Emergency Response Costs

When a gas distribution system incident occurs, local emergency responders, including fire and police, frequently go to the scene to ensure public safety. Although communities are already incurring some of the fixed costs of these services, a gas distribution system incident adds to the cost of emergency response through the cost of responding to more incidents, possibly through damaged equipment and emergency responder injuries or the possible necessity of maintaining a higher overall response capacity.

The number of studies of addressing the costs of firefighting is very limited. In a seminal 1991 paper, William Meade developed estimates for the fully loaded cost of local fire service (i.e., firefighting and other activities and services provided by local fire departments).[32] That paper estimated those costs to be between $25.8 billion and $46.4 billion in 1986, with $39.6 billion the "Most Likely Estimate" of the cost.[33] These estimates consist of the total annual cost of local career fire departments, plus an imputed annual cost for the services provided by volunteer fire departments.[34]

In 1986, according to the National Fire Protection Association, there were a total of 11,890,000 fire department calls.[35] Those included calls for fires, medical aid, false alarms, mutual aid, hazardous materials, other hazardous conditions, and other. Based on the best estimate (i.e., the "Most Likely Estimate") of the cost of local fire service in 1986, and the total number of fire department calls for that same year, a fire call in 1986 cost, on average, $3,331.

For this analysis, PHMSA assumes the cost of a fire department call to be equal to the average cost of a fire department call, $5,425 (this is the $3,331 estimate converted from 1986 to 2006 dollars).

PHMSA assumes that a local fire department will be called for

- 100% of all reportable incidents[36] and
- 10% of all non-reportable incidents.

Based on information developed previously in this report, PHMSA expects

- 85 reportable non-excavation incidents per year,

[32] William P. Meade, "A First Pass at Computing the Cost of Fire Safety in a Modern Society," *Fire Technology*, November 1991, pp. 341-345.
[33] William P. Meade, "A First Pass at Computing the Cost of Fire Safety in a Modern Society," *Fire Technology*, November 1991, pp. 344-345.
[34] William P. Meade, "A First Pass at Computing the Cost of Fire Safety in a Modern Society," *Fire Technology*, November 1991, pp. 344.
[35] Fax from Nancy Schwartz, National Fire Protection Association, to Dianne Sutherland, U.S. DOT, July 8, 1994.

[36] Conversations with local fire protection representatives have indicated that they want to be present at any incident involving a hazardous material.

- 60 reportable excavation incidents per year,
- 66,030 non-reportable, non-excavation incidents per year, and
- 94,856 non-reportable excavation incidents.

Furthermore, due to the high fixed costs in maintaining a fire department, PHMSA assumes that only 25% of the costs of those fire department calls are costs that would not be incurred by local communities in the absence of gas distribution system incidents.[37] PHMSA invites comments on these assumptions.

Thus, PHMSA expects the annual cost savings to local communities and volunteer firefighters in the absence of gas distribution incidents to be $22,017,363 (= (85 + 60 + 6,603 + 9,486) x $5,425 x 0.25). PHMSA assumes that the proposed rule, if implemented, would actually result in 50% of those savings, or $11,008,682 (= $22,017,363 x 0.5). This estimate does not include any cost savings associated with non-gas incidents that might be avoided by the provisions of the proposed rule.

7.1.6 Cost Savings from Avoided Evacuations

When gas distribution system incidents occur, people may be evacuated as a precaution or because of the threat that the incident poses to the public. Table 7 presents information on evacuations resulting from gas distribution system incidents for 2004 and 2005, the only years for which complete evacuation information is available.

TABLE 7. EVACUATIONS RESULTING FROM REPORTED GAS DISTRIBUTION SYSTEM INCIDENTS, 2004-2005[38]

Year	Number of incidents with evacuations	Number of people evacuated	Elapsed time until area was made safe		Estimated Pipeline Miles (Mains and Services)
			Hours	Minutes	
2004	42	4,204	435	13	1,918,270
2005	51	4,725	321	14	1,823,136
Total	**93**	**8,929**	**756**	**27**	

Based on the information in the table, from 2004 through 2005, an average of 2,392 people per million miles, per year, were evacuated due to reported gas distribution incidents.

The cost of evacuations is very difficult to estimate since there are numerous variables. Evacuation costs will include the expense for temporary lodging and food, lost wages, business disruptions, and inconvenience to the public. In addition there are costs of

[37] This appears to be a conservative estimate. According to the National Volunteer Fire Council Fact Sheet (see http://www.nvfc.org/pdf/2005-fact-sheet.pdf), (1) 73% of all firefighters are volunteers and (2) of the 30,542 fire departments in the U.S., 21,671 are staffed entirely by volunteers, while 5,271 are mostly volunteer, 1,582 are mostly career, and 2,018 are staffed entirely by career firefighters.
[38] Source: http://ops.dot.gov/stats/stats.htm

agencies assisting with the evacuation. The U.S. Nuclear Regulatory Commission, for example, uses a range of $600 to $1,800 per person evacuated. The Federal Railroad Administration (FRA) uses $1,000 to estimate impacts from railroad evacuations. [39] Therefore, PHMSA assumes a cost of $1,000 per person for evacuations to be reasonable.[40] We use this figure below, also.

Cost Savings Resulting from Reportable Non-Excavation Incidents

Table 8 presents information on evacuations resulting from gas distribution system incidents for 2004 and 2005.

TABLE 8. EVACUATIONS RESULTING FROM REPORTED NON-EXCAVATION INCIDENTS ON GAS DISTRIBUTION SYSTEMS, 2004-2005[41]

Year	Number of incidents with evacuations	Number of people evacuated	Elapsed time until area was made safe		Estimated Pipeline Miles (Mains and Services)
			Hours	Minutes	
2004	29	530	207	20	1,918,270
2005	36	4,341	180	4	1,823,136
Total	**65**	**4,871**	**387**	**24**	

Based on the information in the table, from 2004 through 2005, an average of 1,329 people per million miles, per year were evacuated due to gas distribution incidents.

For this analysis, PHMSA assumes that incident consequences in the future will mirror those of the recent past. Specifically, PHMSA assumes that the 1,329 people per million miles per year evacuated because of gas distribution incidents will be representative of the future for non-excavation incidents.

Multiplying the estimate of the cost of evacuation per person, $1,000 (see 7.1.6 for the rationale for using this figure), by the number of people per million miles per year, 1,329, yields an estimate of the total cost of evacuations resulting from non-excavation incidents, $1,329,000 per million miles per year.

PHMSA assumes that, as a result of the proposed rule, 50% of the $1,329,000 per million miles per year cost can be avoided. Given that 1.9 million miles of pipeline would be

[39] "Comparative Risks of Hazardous Materials and Non-Hazardous Materials Truck Shipment Accidents/Incidents," FMCSA, Washington, DC, March 2001, p. 2-14. See http://www.fmcsa.dot.gov/documents/hazmatriskfinalreport.pdf.

[40] Gas pipeline incidents can cause further disruptions to nearby businesses and communities, preventing them from carrying on with everyday tasks. Customers and supplies may not be able to reach the establishments and shipments may not be able to leave the establishments even when they are not directly impacted by an evacuation.

[41] Source: http://ops.dot.gov/stats/stats.htm

impacted by the proposed rule, the total annual cost savings resulting from non-excavation incidents is expected to be $1,262,550 (= 1,329,000 x 0.5 x 1.9) per year.

Benefits Resulting from Reportable Excavation Incidents

Table 9 presents information on evacuations resulting from gas distribution system incidents for 2004 and 2005.

TABLE 9. EVACUATIONS RESULTING FROM REPORTED EXCAVATION INCIDENTS ON GAS DISTRIBUTION SYSTEMS, 2004-2005[42]

Year	Number of incidents with evacuations	Number of people evacuated	Elapsed time until area was made safe		Estimated Pipeline Miles (Mains and Services)
			Hours	Minutes	
2004	13	3,674	227	53	1,918,270
2005	15	384	141	10	1,823,136
Total	**28**	**4,058**	**369**	**3**	

Note: In one incident in 2004, 3,000 people were evacuated as a precaution.

Based on the information in the table, from 2004 through 2005, an average of 1,063 people per million miles, per year were evacuated due to reported excavation-related gas distribution incidents.

For this analysis, PHMSA assumes that incident consequences in the future will mirror those of the recent past. Specifically, PHMSA assumes that the 1,063 people per million miles per year evacuated because of gas distribution incidents will be representative of the future for excavation incidents absent this rulemaking.

Multiplying the estimate of the cost of evacuation per person, $1,000, by the number of people per million miles per year, 1,063, yields an estimate of the total cost of evacuations resulting from excavation incidents, $1,063,000 per million miles per year.

PHMSA assumes that, through the actions included in the proposed rule, 50% of the $1,063,000 per million miles per year cost, or $531,500 per million miles per year, can be avoided. PHMSA assumes that 50% of the reduction in evacuation costs would result from the EFV requirements and 50% of the reduction would result from the enhanced damage prevention program requirements. Therefore, the benefits attributable to the enhanced damage prevention program requirements would be $265,750 (= $531,500 x 0.5) per million miles per year. Likewise, the benefits attributable to the EFV requirements would be $265,750 (= $531,500 x 0.5) per million miles per year. Given that 1.9 million miles of pipeline would be impacted by the proposed rule, the total annual cost savings associated with the enhanced damage prevention program requirements is expected to be $1,009,850 (= $265,750 x 2 x 1.9) per year.

[42] Source: http://ops.dot.gov/stats/stats.htm.

Total Benefit from Reduction in Evacuations

In total, the annual benefit from the reduction in the number of evacuations related to reportable incidents would be the sum of the expected benefits from reportable non-excavation evacuations, \$1,262,550 annually, and the expected benefits from reportable excavation evacuations, \$1,009,850 annually, or \$2,272,400 annually. The annual benefit from a reduction in the number of non-reportable incidents has not been estimated because the data needed for such estimation is unavailable. So, for this analysis, PHMSA assumes that the reduction in non-reportable evacuations, in total, would have a benefit that is at least equal to that of reportable evacuations, or \$2,272,400 annually. PHMSA invites comments on the reasonableness of this assumption. Thus, PHMSA estimates that the total benefit from the reduction in evacuations attributable to the proposed rule would be \$4,544,800 annually (= \$2,272,400 x 2).

7.1.7 Benefits Resulting from Reduced Excavation Damage to Non-Gas Distribution System Underground Facilities

As a result of the requirement for operators to implement enhanced damage prevention programs that is included in the proposed rule, not only will gas distribution systems experience fewer dig-ins, but so will other underground facilities. Those other underground facilities include buried communications, CATV, electric, potable water, and sewer facilities, and irrigation pipes and pipelines transporting hazardous liquids or gases.

Currently, comprehensive information on non-gas dig-ins is available only for Colorado. That State requires the owners and operators of underground infrastructure to report dig-ins.[43] The one-call system in Colorado, UNCC (Utility Notification Center of Colorado), publishes an annual report summarizing the information. Colorado law mandates that report.[44] Table 10 presents the number of reported incidents for Colorado from 2001 through 2005. It also presents the number of gas pipeline incidents reported by year and the number of reporting operators, as well as the total number of underground operators who are members of UNCC.

[43] Colorado Revised Statutes (C.R.S.) 9-1.5-103(7)(b).
[44] C.R.S. 9-1.5-103(7)(c)(d) and 9-1.5-105.

TABLE 10. UNDERGROUND FACILITY INCIDENTS IN COLORADO, 2001 – 2005

Year	Total Number of Incidents	Number of Gas Facility Incidents	Number of Reporting Underground Operators / Total Number of Underground Operators
2001	11,092	3,191	65 / “nearly 1,000”
2002	12,704	3,458	71 / NA
2003	13,540	4,489	50 / 1,120
2004	10,573	2,627	40 / 1,126
2005	9,371	2,435	NA / NA

Notes: NA = Not available.
Sources: Utility Notification Center of Colorado, “Perspectives on Facility Damage – 2001,” “Perspectives on Facility Damage – 2002,” “Perspectives on Facility Damage – 2003,” “Perspectives on Facility Damage – 2004,”and “Perspectives on Facility Damage – 2005.”

The gas facilities referenced in the table likely include not only gas distribution systems in Colorado, but also gas transmission and gathering systems.

Based on Colorado’s experience, PHMSA assumes that for each gas distribution system excavation incident, there will be approximately 2.5 non-gas distribution system incidents. That is, PHMSA assumes that the gas pipeline excavation incidents occurring in Colorado were all on distribution systems. Furthermore, based on California’s cost information for non-reportable gas distribution system incidents, PHSMA assumes that the average cost of an excavation incident for non-gas systems is $350 (see Section 6.2.2). Additionally, PHMSA assumes that (1) the implementation of enhanced damage prevention programs by gas distribution systems, as required by DIMP, will reduce the total number of non-gas incidents by 25%, and (2) the installation of EFVs will have no impact on excavation incidents affecting non-gas systems.

Enhanced damage prevention programs will have an impact on the number of dig-ins experienced by other underground facilities. Such programs should make excavators sensitive to the risks they pose not only to underground gas distribution services and mains, but also to any and all underground facilities.

It should be recognized that the installation of EFVs actually would have some very limited impact on excavation incidents affecting non-gas systems because gas incidents that include fires or explosions sometimes adversely impact nearby underground facilities. The frequency that this occurs, however, is expected to be low.

For Colorado from 2001 through 2005, a total of eight excavation-related incidents on gas distribution systems were reported to PHMSA (3 in 2001, 2 in 2002, 0 in 2003, 1 in 2004, and 2 in 2005). Thus, for every reported gas distribution dig-in incident there were 5,135 (= 41,080 / 8) non-gas dig-ins. Assuming that this is the situation nationally, and using the average annual number of reported gas distribution system excavation incidents from 2001 through 2005, 60, which can be calculated using the information in Table 5, a value for the non-gas incidents avoided annually because of enhanced damage prevention programs can be estimated. That value is $26,958,750 (= 60 x 5,135 x 0.25 x $350).

This estimate may understate the true cost savings to non-gas operators from the enhanced damage prevention programs that gas distribution operators will implement under DIMP for several reasons, since, among other reasons, it does not include avoided dig-ins on gas transmission and gathering lines. Furthermore, it is not based on the incidents occurring on all underground facilities in Colorado, as the last column in Table 10 implies.

7.1.8 Cost Savings Associated with Ending the Currently Existing EFV Notification Requirement

By mandating the installation of EFVs, with limited exceptions, on all new and renewed single-family residential services operating at least 10 psig, the proposed rule renders moot the currently existing customer notification requirement concerning EFVs (see 49 CFR 192.383). Consequently, PHMSA proposes, as part of the proposed rule, to relieve distribution system operators of the EFV notification requirement. PHMSA estimates that 400,000 notifications annually would no longer need to be made (for the derivation of this estimate, see Section 6.3.4.3 of this report).

If the EFV notification requirement were to be rescinded, distribution system operators would experience lower costs because they would no longer need to (1) mail out EFV notifications or (2) answer the questions of those receiving the notifications.

With respect to the cost of mailing notifications, PHMSA makes the following assumptions:[45]

- The cost of postage is $0.41.
- The cost of the physical copy of the notification is $0.10.
- Preparing and mailing each notification takes 5 minutes of staff time.
- Those preparing and mailing the notifications have a fully loaded labor cost of $17.60 per hour.

Based on these assumptions, the total cost savings attributable to not having to annually mail notifications to 400,000 single family residential customers with new or renewed services would be $790,667 (= 400,000 x ($0.41 + $0.10 + (5/60 x $17.60))) per year.

With respect to the cost of answering the questions of those receiving notifications, PHSMA makes the following assumptions:[46]

[45] These assumptions are based on, but not necessarily identical to, those found in the Final Rule for Excess Flow Valve Notification, which was published in the *Federal Register*, Vol. 63, 1998, pp. 5464-5471.
[46] These assumptions are based on but not necessarily identical to those found in the Final Rule for Excess Flow Valve Notification, which was published in the *Federal Register*, Vol. 63, 1998, pp. 5464-5471.

- 10% of all of those receiving EFV notifications will call for more information.
- The calls made will take, on average, five minutes to answer.
- Those answering the calls have a fully loaded labor cost of $40 per hour.

Based on these assumptions, the total cost savings attributable to not being required to answer the questions of those receiving notifications about EFVs on their new or renewed service lines would be $133,333 (= 400,000 x 0.1 x (5/60) x $40) per year.

In total, the cost savings attributable to not being required to notify 400,000 customers annually would be $924,000 (= $790,667 + $133,333). This is PHMSA's estimate of the value of the regulatory relief that the gas distribution industry would realize annually by eliminating the EFV notification requirement.

7.1.9 Total Benefits

Table 11 presents a summary of the estimated benefits of the proposed rule, along with the calculated total for those benefits. In total, the benefits of the proposed rule are expected to be $214 million per year. The $214 million estimate does not include any estimates for the benefits associated with (1) reduced GHG emissions, (2) increased public confidence, or (3) additional costs savings to industry.

TABLE 11. SUMMARY AND TOTAL FOR THE ESTIMATED BENEFITS OF THE PROPOSED RULE

Benefit	Estimate (Million dollars per year)
Reduced Reportable Incidents	$60
Reduced Non-reportable Incidents	$28
Reduced High Consequence Costs	$6
Reduced Lost Gas	$76
Reduced Emergency Response Costs	$11
Reduced Evacuations	$5
Reduced Non-Gas Excavations	$27
End of Existing EFV Notification Requirement	$1
TOTAL	$214

The present value of the estimated $214 million in expected annual benefits over 50 years using a 3% discount rate would be approximately $5.5 billion. The present value of the annual benefits over 50 years using a 7% discount rate would be approximately $3.0 billion.

7.2 Costs

The costs associated with the proposed rule will be attributable to the following activities that will be required of natural gas distribution systems:

- Developing an integrity management program
- Implementing an integrity management program
- Mitigating risks
- Managing the integrity management program
- Reporting to PHMSA and State regulators
- Recordkeeping

Each of these activities and their associated costs are discussed below, following a brief overview of the key assumptions used in the calculation of the costs.

7.2.1 Assumptions

Table 12 lists the key assumptions concerning distribution system characteristics, costs, and other items that are used in the estimation of the costs of the proposed rule.

TABLE 12. KEY ASSUMPTIONS IMPACTING COST

Item	
Distribution System Characteristics*	
Total miles of steel mains	546,950
Total miles of plastic mains	531,365
Total miles of cast iron mains ≤ 8" in diameter	34,578
Miles of bare steel main to be replaced with plastic	57,297
Miles of bare steel main to be replaced with coated steel	18,682
Miles of PVC + ABS mains	45,000
Total number of steel services	22,496,190
Total number of plastic services	37,309,715
Total number of cast iron services	128,993
Total number of copper services	1,339,000
Number of bare steel services	4,554,000
Number of PVC + ABS services	1,900,000
Costs*	***Assumed Value***
Costs to replace cast iron (high density underground)	$90/foot
Costs to replace steel w/ coated steel	$77/foot
Costs to replace steel w/ plastic	$25/foot
Costs to replace steel w/ plastic (high density underground)	$45/foot
Cost to replace service – high density underground	$2,200/service
Cost to replace service – medium density underground	$1,500/service
Cost to replace service – low density underground	$1,000/service
Cost of EFV installation on new or replacement services for large operators	$20/service
Cost of EFV installation on new or replacement services for	$30/service

Item	
small operators	
Fully loaded cost of pipeline employees – Large and small operators	$70/hour
Fully loaded cost of pipeline employees – Master meter and LPG systems	$50/hour
Cost of leak survey on a main	$175/mile
Cost of leak survey on a service	$2.25/service
Other	
Cast iron replacement programs	65% of lines covered, so 35% of lines not covered***
Bare steel replacement programs	74% of lines covered, so 26% of lines not covered***
Vintage plastic replacement activities	75% of lines covered, so 25% of lines not covered**

*2004 data.
**From industry sources (except for the fully loaded cost of master meter and LPG system pipeline employees, which is a PHMSA estimate).
***From AGF report. Assumed to be valid for all local gas utilities.

7.2.2 Developing an Integrity Management Program

The proposed rule requires that each gas distribution system operator develop a formal integrity management program within 18 months after the final rule is issued. As stated previously, the integrity management program is intended to manage the risks associated with the operator's pipeline system. For distribution operators other than master meter and LPG gas operators, an integrity management program must, at a minimum, include the following elements:

- Demonstrated knowledge of the pipeline system's infrastructure.
- Identification of existing and potential threats to the system.
- Risk evaluation and prioritization.
- Identification and implementation of risk mitigation measures.
- Performance measures, monitoring of results, and evaluation of program effectiveness.
- Continual evaluation and, if necessary, improvement of the integrity management program.
- Periodic reporting of results.

Since integrity management programs are not currently required for gas distribution systems, the costs associated with developing such a program are unknown and must be estimated. Because conditions differ among the types of operators, the costs associated with developing the programs will be estimated separately for large operators, small operators, and master meter and LPG gas systems.

Based on discussions with industry organizations representing the operators that will be affected by the proposed regulatory changes, PHMSA has identified the following as the key activities associated with the development of a formal integrity management program:

- Preparing a written distribution integrity management program.
- Documenting the DIMP processes.
- Identifying threats.

The American Public Gas Association (APGA) Security and Integrity Foundation (SIF) will develop a model Distribution Integrity Management Program to assist small operators in developing integrity management programs meeting the requirements of a final rule. The end product will be a simple and handy, risk-based integrity management program to help small operators hold down the cost of developing IMPs.

Additionally the proposed rule includes an even more simplified approach for developing an integrity management program aimed at master meter and LPG systems. This will help master meter and LPG systems control their integrity management program development costs.

Table 13 presents PHMSA's estimates of the costs for these activities listed by operator type. In total, PHMSA estimates that the cost of the activities will be $66.7 million dollars in the first year and $7.5 million in each subsequent year. Of this total, large operators will pay $36.1 million in the first year and $4.1 million in each subsequent year, small operators will pay $17.8 million in the first year and $1.8 million in each subsequent year, and master meter and LPG systems will pay $12.8 million in the first year and $1.6 million in each subsequent year.

TABLE 13. ESTIMATED COSTS OF DEVELOPING AN INTEGRITY MANAGEMENT PROGRAM

Type of Operator and Activity	Number of Operators	Labor Hours per Operator	Labor Rate (Fully loaded cost per labor hour)	Total Annual Cost in Year 1 ($ Million)	Total Annual Cost in Year 2 and On ($ Million)
Large Operators					
DIMP Preparation	201	960	$70	$13.5	---
Documenting DIMP processes	201	800	$70	$11.3	---
Identifying threats	201	800	$70	$11.3	---
Periodic updates and	201	288	$70	---	$4.1

Type of Operator and Activity	Number of Operators	Labor Hours per Operator	Labor Rate (Fully loaded cost per labor hour)	Total Annual Cost in Year 1 ($ Million)	Total Annual Cost in Year 2 and On ($ Million)
revisions					
TOTAL				$36.1	$4.1
Small Operators					
DIMP Preparation	1,090	Total cost per operator: $5,000		$5.5	---
Documenting DIMP processes	1,090	40	$70	$3.1	---
Identifying threats	1,090	120	$70	$9.2	---
Periodic updates and revisions	1,090	24	$70	---	$1.8
TOTAL				$17.8	$1.8
Master Meter and LPG Systems					
DIMP Preparation	8,000	Total cost per operator: $1,000		$8.0	---
Documenting DIMP processes	8,000	4	$50	$1.6	---
Identifying threats	8,000	8	$50	$3.2	---
Periodic updates and revisions	8,000	4	$50	---	$1.6
TOTAL				$12.8	$1.6
Grand Total					
GRAND TOTAL				$66.7	$7.5

On a per operator basis, the cost of developing an IMP for large operators will be approximately $180 thousand in the first year and $20 thousand in each subsequent year, the cost for small operators will be approximately $16 thousand in the first year and $2,000 in each subsequent year, and the cost for master meter and LPG systems will be approximately $2,000 in the first year and less than $500 in each subsequent year.

7.2.3 Implementing an Integrity Management Program

Distribution system operators will have 18 months after the final rule is issued to develop and implement their integrity management programs. The time allowed between the issuing of the final rule and integrity management program implementation is provided in order to allow operators to make any modifications their operations and maintenance procedures may need, as well as any modifications their business practices may need.

Implementation of integrity management programs includes a variety of activities, such as assembling and reviewing information about the infrastructure of an operator's pipeline, evaluating threats and risks, measuring performance, and deciding on improvements. These activities will generally need to be undertaken by experienced pipeline safety professionals.

A key element of integrity management program implementation will be the active and continual integration of all information relevant to the integrity of the pipeline covered by that program. This integration is essential if pipeline operators are to fully consider the unique risks that each of their individual distributions systems pose. Successful integrity management requires operators to view their systems as a whole, and information integration is the general mechanisms that will allow them do that.

Based on discussions with industry organizations representing operators that will be affected by the proposed regulatory changes, PHMSA identified the following as being key activities associated with the implementation of an integrity management program:

- Software acquisition (or upgrade)
- Data acquisition and analysis
- Database maintenance

Table 14 presents PHMSA's estimates of the cost of integrity management implementation listed by type of operator. Those estimates were developed following discussions with industry representatives.

For this analysis, only large operators are assumed to need to acquire or upgrade risk analysis software. Software acquisition includes not only the purchase of risk-analysis software, but also the cost of any training that may be needed. It assumes that the operators have in-house personnel who can successfully operate the software (with training). In addition, only large operators are assumed to need significant database maintenance. The costs of database maintenance for small operators and master meter and LPG systems are expected to be nominal.

In total, PHMSA estimates that the cost of the data analysis activities will be $57.5 million dollars in the first year and $20.7 million in each subsequent year. Of this total, large operators will pay $36.0 million in the first year and $11.8 million in each subsequent year, small operators will pay $18.3 million in the first year and $7.3 million in each subsequent year, and master meter and LPG systems will pay $3.2 million in the first year and $1.6 million in each subsequent year.

TABLE 14. ESTIMATED COSTS OF IMPLEMENTING AN INTEGRITY MANAGEMENT PROGRAM

Type of Operator and Activity	Number of Operators	Labor Hours per Operator	Labor Rate (Fully loaded cost per labor hour)	Total Annual Cost in Year 1 ($ Million)	Total Annual Cost in Year 2 and On ($ Million)
Large Operators					
Software	201	Total cost per operator: $25,000		$5.0	---
Data acquisition and analysis	201	2,200 in yr. 1; 480 in yrs. 2 & on	$70	$31.0	$6.8
Database maintenance	201	Total cost per operator: $25,000		---	$5.0
TOTAL				$36.0	$11.8
Small Operators					
Software	1,090	---	---	---	---
Data acquisition and analysis	1,090	240 in yr. 1; 96 in yrs. 2 & on	$70	$18.3	$7.3
Database maintenance	1,090	---	---	---	---
TOTAL				$18.3	$7.3
Master Meter and LPG Systems					
Software	8,000	---	---	---	---
Data acquisition and analysis	8,000	8 in yr. 1; 4 in yrs. 2 & on	$50	$3.2	$1.6
Database maintenance	8,000	---	---	---	---
TOTAL				$3.2	$1.6
Grand Total					
GRAND TOTAL				$57.5	$20.7

On a per operator basis, the cost of implementing an integrity management program for large operators will be approximately $179 thousand in the first year and $59 thousand in each subsequent year. The cost for small operators will be approximately $17 thousand in the first year and $7 thousand in each subsequent year, and the cost for master meter and LPG systems will be less than $500 in the first year and less than $500 in each subsequent year.

7.2.4 Mitigating Risks

As part of an overall integrity management program, the proposed rule requires operators to take action to mitigate any known risks and thereby improve the safety of their systems. The specific actions taken will vary depending on the applicable threats, their prevalence, and the current risks posed by the pipelines. In addition to any other risk reduction programs they may implement, the proposed rule requires all operators to implement two particular risk reduction programs: (1) an effective leak reduction program and (2) an enhanced damage prevention program. Additionally, under the proposed rule, EFV installation is mandatory, with limited exceptions. Master meter and LPG systems would be exempt from this requirement.

Leak Management

In distribution systems one significant element of operator efforts to manage risks is identifying and fixing severe leaks. These leaks, whatever their cause, can lead to gas migration to buildings, accumulation in these buildings, ignition and fire - potentially causing injury or death to residents. All operators are currently required to periodically survey for leaks. The DIMP requirements will strengthen existing leak detection requirements.[47] The five elements of leak detection management plan are:

- Locate the leak.
- Evaluate its severity.
- Act to mitigate the hazard.
- Keep records.
- Self-assess to determine if additional actions are necessary to keep the system safe.

Operators that that do not repair, but monitor, non-hazardous leaks will need to include criteria in the DIMP plan for evaluating their potential hazard.

The net effect of leak management requirements in DIMP would be to reduce leak-caused incidents by redirecting operator resources to higher risk segments of piping.

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[47] Some States have leak management requirements or programs exceeding Part 192; however, these are often tailored for the local conditions (or types of systems) and may not be applicable to all operators in a given State or throughout the country. At this time, they do not appear appropriate for national requirements, but can be considered by operators in developing their individualized risk control program.

Industry sources indicate that operators would increase their leak surveys as a consequence of the proposed rule and also to increase the mileage of pipe replaced. Additional pipe may also be replaced for reasons other than leak management, of course. The requirement will help ensure that operators have leak management programs that adequately protect the public. Additionally, the requirement should help ensure that distribution system operators readily adopt any future improvements in leak management.

Damage Prevention

Under 49 CFR 192.614, all natural gas distribution systems must have a program to prevent damage from excavation activities, including excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures, and other earthmoving operations. Gas pipeline operators may comply with any of the requirements of the section 192.614 through participation in a public service program, such as a one-call system. Furthermore, if a qualified one-call system operates in the area, gas pipeline operators must participate in it. A one-call system is considered a qualified one-call system if it operates in a State that has adopted a one-call damage prevention program under 49 CFR 198.37 or if it is operated in accordance with 49 CFR 198.39.

PHMSA incorporated by reference the guidelines provided in the American Petroleum Institute (API) Recommended Practice (RP) 1162, ''Public Awareness Programs for Pipeline Operators.'' (See 49 CFR 192.616.) The regulations require that an operator follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.[48]

In addition to damage prevention programs, public awareness programs can also help reduce excavation damage to pipelines. As the term implies, the basic purpose of public awareness programs is to educate the general public about the presence of, and the potential danger inherent, in pipelines. An effective public awareness program can increase awareness of the risks caused by unintentional pipeline releases and their impact on the public and the environment. Public awareness programs identify how risks can be prevented or mitigated. Through public awareness, these programs can help prevent excavation damage, as well as reduce encroachment on pipeline rights-of-way, improve pipeline safety, and enhance emergency response.

Currently, natural gas distribution system operators have excavation damage prevention programs. In addition, all natural gas distribution system operators have public awareness programs, although PHMSA is currently in the process of relieving master meter and LPG systems from the requirement.

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[48] "Integrity Management for Gas Distribution. " Report of Phase I Investigations", December 2005. Excavation Damage Group Report, p.188. See http://www.cycla.com/opsiswc/docs/S8/P0068/DIMP_Phase1Report_Final.pdf.

PHMSA and its constituents fully endorse maximum, effective damage prevention. All parties believe these programs are vital to continued improvements in damage prevention and safe pipeline operations. The proposed rules would require gas distribution system operators to develop and implement an enhanced damage prevention program. This would go beyond what the operators currently have in place. As the PIPES Act indicates, such a program should, at a minimum, have the following elements:

- Enhanced communications between pipeline system operators and excavators
- The fostering of support and partnership among all stakeholders
- The use of performance measures by operators
- A partnership in employee training
- A partnership in public education
- A dispute resolution process
- The use of technology, where appropriate, to improve processes
- The analysis of data to periodically evaluate and improve program effectiveness.

Natural gas distribution system operators have some requirements of excavation of the damage prevention and public awareness programs; however, substantial differences are exist among operators' programs.[49] Results of a National Association of Pipeline Safety Representatives (NASPR) survey (conducted in 2004-2005) indicated States can and do exercise authority beyond minimum Federal requirements. Additional requirements are focused in scope, and vary from State to State, based on local needs and issues. Programs to replace older, inferior infrastructure are the most widespread practice beyond Federal requirements. Such programs are in progress in two-thirds of the States, but some of these programs are of limited scope (i.e., affecting a single operator). [50] Still, despite these State efforts, serious incidents continue to occur on distribution pipeline systems.

For operators with programs that incorporate most (or some) of the elements required by this rule, the rule will enhance their programs by building on elements that already exist (e.g., public awareness programs), or would exist under the proposed rule (e.g., performance measures). These operators' costs will not increase (or at least not increase significantly). For operators that do not have many of the elements of the proposed rule in place, there will be additional costs. PHMSA does not know to what extent the costs would increase for those entities. PHMSA invites comment on this.

Excess Flow Valves

An excess flow valve (EFV) is a device that can be installed in a service line to automatically shut off the flow of gas if that service line is severed or severely damaged downstream of the valve. EFVs can thus mitigate the consequences of such incidents.

[49]PHMSA is currently in the process of relieving master meter and LPG systems from the public awareness requirement.
[50] NAPSR's members are the managers of the pipeline safety regulatory staff from each state (and the District of Columbia) that is certified by, or a designated agent of, DOT for regulatory oversight.

As required by Section 11 of the PIPES Act, the proposed rule requires gas distribution system operators (with the exception of master meter and LPG systems) to install EFVs on single family residential service lines if

- The service line is installed or entirely replaced after June 1, 2008
- The service line operates continuously throughout the year at a pressure of not less than 10 psig
- The service line is not connected to a gas stream with contaminants that could interfere with the operation of an excess flow valve.
- The installation is not likely to cause loss of service to the residence or interfere with necessary operation or maintenance activities, such as purging liquids from the service line, and
- An excess flow valve is available that meets the performance standards in 49 C.F.R. 192.381.

Operators of natural gas service lines must report annually on the number of excess flow valves installed on their systems.

After discussions with industry organizations representing operators that will be affected by the proposed regulatory changes, PHMSA estimates that an additional 400,000 EFVs would be installed annually as a direct consequence of the proposed rule.[51] To derive this estimate, PHMSA assumes that large and small gas distribution system operators install approximately 1,250,000 new services annually and completely replace 500,000 services annually. Of these 1,750,000 services, approximately 31%, or 542,500 services (= 1,750,000 x 0.31), do not have the proper operating conditions for an EFV (i.e., they operate at less than 10 psig, are services off cast iron mains, or are multi-family services). Of the remaining 1,207,500 services (= 1,750,000 – 542,500), PHMSA estimates that 66%, or 796,950 services (= 1,207,500 x 0.66), would have EFV installed in them even in the absence of the proposed rule. That leaves 410,550 services (= 1,207,500 – 796,950). Of those, approximately 10,550 are estimated to be inappropriate for EFVs because of line contaminants or other reasons. That leaves 400,000 services (= 410,550 – 10,550) annually upon which EFVs could be installed.

Of the 400,000 additional EFVs estimated to be installed annually to meet the proposed requirement, PHMSA estimates that large operators would install 364,966 additional EFVs (= 400,000 x 54.9/60.17), while small operators would annually install 35,034 additional EFVs (= 400,000 x 5.27/60.17).[52] PHMSA expects that the installation of EFVs, including the cost of those EFVs, would be $20 for large operators and $30 for small operators. Consequently, the additional annual costs for large operators attributable to EFVs would be $7,299,320 (= 364,966 x $20), while the additional annual costs for small operators attributable to small operators would be $1,051,020 (= 35,034 x $30). Master meter and LPG systems would not be required to install EFVs under the proposed

[51] That is, 400,000 EFVs over and above what operators currently install would be installed as a consequence of the proposed rule.

[52] From Table 1, large operators have 54,900,000 services and small operators have 5,270,000 services. In total, large and small operators together have 60,170,000 services.

rule. In total, the additional annual costs attributable to EFVs would be $8,350,340 (= $7,299,320 + $1,051,020).

Mitigating Other Risks

The proposed rule would require operators to use their measured performance to determine whether further improvements are needed and, if so, to make appropriate changes to their integrity management programs, their infrastructure, and their operations and maintenance activities. All operators are required to conduct continual program evaluations (i.e., reviews of their measured performance) at least once every five years. Consequently, at least once every five years, operators will need to identify and make any changes needed by their integrity management programs, as well as to their infrastructure and the operations and maintenance activities covered by those programs.

The costs associated with this review requirement will be contingent on (1) the problems and issues revealed by the performance measures, (2) the frequency of reviews, and (3) the selected solutions to problems and approaches to handling issues. Because of these uncertainties, the costs of mitigating other risks are difficult to estimate. For this analysis, PHMSA estimates that the costs of mitigating other risks will equal 10% of the sum of the estimates for all other mitigation.

Estimated Costs of Mitigation

The costs of mitigation resulting from the proposed rule are unknown and must be estimated. The field activities that an operator could take to comply with the proposed rule include :

- Replacing additional pipe.
- Performing more leak surveys.
- Installing additional EFVs.
- Performing other field activities.

PHMSA recognizes that there are significant differences among operators regarding risk assessment. Although mitigation of risk is a fundamental requirement, under the proposed rule, operators retain the flexibility to choose the mitigative activities they pursue. PHMSA expects that operators will perform the most cost-effective mitigation activities to fulfill the requirements.

Table 15 presents the estimated costs of all field activities associated with the mitigation of risks required by the proposed rule. As mentioned previously, for this analysis, the costs of performing other activities are assumed to be equal to 10% of the combined estimated cost of all other field activities (i.e., 10% of the costs of replacing additional pipe plus the costs of performing more leak surveys plus the costs of installing additional EFVs). The estimates in Table 15 were developed after consultation with industry organizations representing operators that will be affected by the proposed regulatory changes.

In developing the estimates presented in Table 15, it has been assumed,[53] as indicated in Table 12, that 35% of all cast iron lines are not currently covered by cast iron pipe replacement programs, 26% of all bare steel lines are not currently covered by bare steel replacement programs, and 25% of all plastic lines are not currently covered by vintage plastic replacement activities. Furthermore, for large operators, it has been assumed that:

- An additional 3.5% of cast iron mains and services will be replaced over a period of 50 years. This is 10% of the 35% of cast iron mains and services not currently covered by a replacement program.[54]
- An additional 1.3% of bare steel mains and services will be replaced over a period of 50 years. This is 5% of the 35% of bare steel mains and service not currently covered by a replacement program.[55]
- An additional 5% of copper services will be replaced over a period of 50 years.
- An additional 2.5% of plastic mains and services will be replaced over a period of 50 years.

Similarly, for small operators, it has been assumed that:

- An additional 2.6% of bare steel mains and services will be replaced over a period of 50 years.
- An additional 10% of copper services will be replaced over a period of 50 years.
- An additional 5% of plastic mains and services will be replaced over a period of 50 years.

Finally, for master meter and LPG systems, it has been assumed that:

- An additional 35 miles of bare steel mains will be replaced over a period of 50 years.
- An additional 3,604 bare steel services will be replaced over a period of 30 years.
- An additional 49 miles of plastic mains will be replaced over a period of 30 years.
- An additional 3,615 plastic services will to be replaced over a period of 30 years.

It should be noted, these actions are over and above replacement that is currently being undertaken by distribution system operators.

The estimated costs of cast iron and bare steel pipe replacement on mains used in this analysis ($475,200 per mile and $279,145 per mile, respectively) may be high given that new technology allows plastic liners to be inserted inside existing pipe. This technology should be dramatically less costly than digging up and physically replacing the existing pipe.

[53] Assumptions are based upon information from industry sources, except where specified.
[54] See the American Gas Foundation, "Safety Performance and Integrity of Natural Gas Infrastructure," January 2005, at http://www.gasfoundation.org/ResearchStudies/safety_perf.htm.
[55] See the American Gas Foundation, "Safety Performance and Integrity of Natural Gas Infrastructure," January 2005, at http://www.gasfoundation.org/ResearchStudies/safety_perf.htm.

The estimates in Table 15 are listed by type of operator. In total, PHMSA estimates that the cost of the field activities will be $60.4 million dollars in the second and each subsequent year. Of this total, large operators will pay $53.1 million in the second and each subsequent year, small operators will pay $5.8 million in the second and each subsequent year, and master meter and LPG systems will pay $1.5 million in the second and each subsequent year.

On a per operator basis, the cost of integrity management program field activities for large operators will be approximately $264,000 in the second and each subsequent year, the cost for small operators will be approximately $5,000 in the second and each subsequent year, and the cost for master meter and LPG systems will be less than $500 in the second and each subsequent year.

TABLE 15. ESTIMATED COSTS OF INTEGRITY MANAGEMENT PROGRAM MITIGATION

Type of Operator and Activity	Cost	Miles of main or number of services impacted, or labor hours required	Total Annual Cost in Year 1 ($ Million)	Total Annual Cost in Year 2 and On ($ Millions)
		Large Operators		
Replacing additional pipe--				
-≤8" cast iron mains	$475,200/mile	24.2 miles	$0	$11.5
-Cast iron services	$2,200/service	90.3 services	$0	$0.2
-Bare steel mains	$279,145/mile	17.5 miles	$0	$4.9
-Bare steel services	$2,200/service	1,064 services	$0	$2.3
-Copper services	$2,200/service	1,203.1 services	$0	$2.6
-Plastic mains	$132,000/mile	19.9 miles	$0	$2.6
-Plastic services	$2,200/service	854 services	$0	$1.9
-SUBTOTAL			$0	$26.0
Performing more leak surveys--				
-On mains	$175/mile	50,500 miles	$0	$8.8
-On services	$2.25/service	2,745,000 services	$0	$6.2
-SUBTOTAL			$0	$15.0
Installing additional EFVs on services	$20/service	364,966 services	$0	$7.3
Performing other activities			$0	$4.8
TOTAL			$0	$53.1

Type of Operator and Activity	Cost	Miles of main or number of services impacted, or labor hours required	Total Annual Cost in Year 1 ($ Million)	Total Annual Cost in Year 2 and On ($ Millions)
Small Operators				
Replacing additional pipe--				
-Bare steel mains	$279,145/mile	4.2 miles	$0	$1.2
-Bare steel services	$1,500/service	204.3 services	$0	$0.3
-Copper services	$1,000/service	232.7 services	$0	$0.2
-Plastic (PVC, ABS) mains	$132,000/mile	4.7 miles	$0	$0.6
-Plastic (PVC, ABS) services	$1,000/service	163.9 services	$0	$0.2
-SUBTOTAL			$0	$2.5
Performing more leak surveys--				
-On mains	$175/mile	6,000 miles	$0	$1.1
-On services	$2.25/service	263,500 services	$0	$0.6
-SUBTOTAL			$0	$1.7
Installing additional EFVs on services	$30/service	35,034 services	$0	$1.1
Performing other activities			$0	$0.5
TOTAL			$0	$5.8
Master Meter and LPG Systems				
Replacing additional pipe--				
-Bare steel mains	$156,667/mile	0.7 miles	$0	$0.1
-Bare steel services	$1,500/service	72.1 services	$0	$0.1
-Copper services	$1,000/service	679.4 services	$0	$0.7
-Plastic (PVC, ABS) mains	$132,000/mile	1.6 miles	$0	$0.2
-Plastic (PVC, ABS) services	$1,000/service	120.5 services	$0	$0.1
-SUBTOTAL			$0	$1.2
Performing more leak surveys--				
-On mains	$175/mile	800 miles	$0	$0.1
-On services	$2.25/service	80,000 services	$0	$0.2
-SUBTOTAL			$0	$0.3
Performing other activities	---	---	$0	$0.0
TOTAL			$0	$1.5

Type of Operator and Activity	Cost	Miles of main or number of services impacted, or labor hours required	Total Annual Cost in Year 1 ($ Million)	Total Annual Cost in Year 2 and On ($ Millions)
Grand Total				
GRAND TOTAL			$0	$60.4

Notes: (Assumptions based on information from industry sources, except where specified)
(1) Examples of activities that might be undertaken under "Performing other activities" include
--Correcting cathodic protection deficiencies to combat external corrosion
--Installing pipe liners to combat internal corrosion
--Improving the accuracy of line locating to combat third party and operator damage
--Relocating facilities that are hard to protect to combat vandalism.
(2) For large operators:
--An additional 3.5% of cast iron mains and services are assumed to be replaced over a period of 50 years. This is 10% of the 35% of cast iron mains and services not currently covered by a replacement program (see the American Gas Foundation, "Safety Performance and Integrity of Natural Gas Infrastructure," January 2005, at http://www.gasfoundation.org/ResearchStudies/safety_perf.htm).
--An additional 1.3% of bare steel mains and services are assumed to be replaced over a period of 50 years. This is 5% of the 35% of bare steel mains and service not currently covered by a replacement program (see the American Gas Foundation, "Safety Performance and Integrity of Natural Gas Infrastructure," January 2005, at http://www.gasfoundation.org/ResearchStudies/safety_perf.htm).
--An additional 5% of copper services are assumed to be replaced over a period of 50 years.
--An additional 2.5% of plastic mains and services are assumed to be replaced over a period of 50 years.
--EFVs are installed annually on 364,966 services (see Sec. 6.3.3.3).
(3) For small operators:
--Steel and copper replacements are prorated from large operators using mileage or number of services, as appropriate.
--An additional 2.6% of bare steel mains and services are assumed to be replaced over a period of 50 years.
--An additional 10% of copper services are assumed to be replaced over a period of 50 years.
--An additional 5% of plastic mains and services are assumed to be replaced over a period of 50 years.
--EFVs are installed annually on 35,034 services (see Sec. 6.3.3.3).
(4) For master meter and LPG systems:
--An additional 35 miles of bare steel mains are assumed to be replaced over a period of 50 years.
--An additional 3,604 bare steel services are assumed to be replaced over a period of 50 years.
--An additional 20,381 copper services are assumed to be replaced over a period of 30 years.
--An additional 49 miles of plastic mains are assumed to be replaced over a period of 30 years.
--An additional 3,615 plastic services are assumed to be replaced over a period of 30 years.

State Requirements

Distribution pipelines are intrastate pipelines. Under the pipeline safety program, certified States may exercise regulatory oversight over these operations. A certified State must enforce at least the Federal regulations, but may also impose additional requirements. States also foster programs that improve pipeline safety outside their regulatory structure, for example, via their rate setting process.

A 2004-2005 survey by the National Association of Pipeline Safety Representatives (NAPSR) identified that many States impose additional safety requirements on gas distribution pipelines.[56] Many of these requirements address actions to prevent or detect damage by outside forces or to conduct additional surveys to detect and repair leaks. In addition, approximately two-thirds of States have some type of program to require replacement of certain types of distribution pipeline (e.g., cast iron, uncoated steel, copper, and some kinds of plastic pipe) that are more prone to failures resulting in release of gas and therefore accident risk.

These additional State requirements help ensure the integrity and safety of gas distribution pipelines. The costs associated with these requirements are assumed to have already been incurred. PHMSA invites comment on this.

Gas Distribution System Operators with DIMP-like Programs

There are significant differences among operators' risk assessment and safety programs, some are comprehensive while others are less so. PHMSA is attempting to standardize industry practices, while providing enough flexibility to accommodate the diversity. Some gas distribution operators are expected to already have some programs similar to the one in the proposed rule. PHMSA expects that such programs cover perhaps as much as 25% of all distribution system mileage.

Some of the features of the DIMP programs that have been already implemented by operators are based on the State requirements mentioned previously. Some operators may have implemented other programs because they make good business sense. They reduce the overall costs of those operators. PHMSA assumes some of the costs associated with these requirements may have already have been incurred by some operators, but because of the differences among operators' programs and the different ways they may choose to address the requirements, PHMSA can not estimate the magnitude of the additional costs. PHMSA invites comments on this.

7.2.5 Reporting to PHMSA and State Regulators

The proposed rule would require each impacted operator, except master meter and LPG systems, to report certain performance measures to PHMSA and State regulators annually. The report to PHMSA must be made as part of the annual report required by 49 CFR 191.11. That report must contain information about the following four performance measures:

- Number of leaks removed per section 192.793(c) (i.e., because they were hazardous), by cause.
- Number of excavation damages.
- Number of excavation tickets.
- Number of EFVs installed.

Other performance measures that might also be included in the required reports are:

[56] For a more detailed summary, see the Notice of Proposed Rulemaking. For details about the survey, see documents 73 and 74 in Docket RSPA-2004-19854.

- Total number of leaks removed, categorized by cause.
- Number of leaks removed per section 192.793(c) (i.e., because they were hazardous), categorized by material.
- Percentage of each pipe material in operator's system.
- Progress in refining the operator's understanding of its infrastructure.

Distribution operators will incur additional reporting costs attributable to the proposed rule. PHMSA expects the costs will depend on the type of operation and experience of the operator with reporting. PHMSA believes that typically there is a learning curve when operators are subject to new requirements. Based on past experience with different rules, PHMSA estimates that the cost to add additional information to the annual report will be nominal. (The average hourly wage for a compliance officer is estimated at $40 per hour, including benefits. If we assume that the additional time to include these parameters in their annual reports is 1 hour per operator, the additional cost per operator, per year would be would be about $40 ($40*1)). This estimate also assumes that the format of the information provided to PHMSA in the annual reports will be acceptable to the States and no additional reports or telephone communication will be needed to comply with the requirement. PHMSA invites comment on this.

7.2.6 Recordkeeping

The proposed rule would require that each operator impacted by that rule keep certain records. At a minimum, those records must include

- A written integrity management program
- Documents supporting threat identification
- A written procedure of ranking threats
- Documents supporting any decision, analysis, or process developed and used to implement and evaluate each element of the integrity management program
- Records identifying changes made to the integrity management program or its elements, including a description of the changes and the reasons they were made

Operators must keep the records for the useful life of the pipeline.

Based on previous experience with record keeping requirements, PHMSA expects the cost of the required recordkeeping to be nominal. Some of the required records will be kept electronically, while others will be kept on paper. In the case of those kept electronically, the required recordkeeping will necessitate a company clerk entering data and in some cases scanning materials. In the case of those kept on paper, the required recordkeeping will necessitate a company clerk placing materials in file folders, placing the file folders in file cabinets, and retrieving files, when needed. It may also necessitate a system for signing materials in and out. Finally, in some cases, physical recordkeeping may necessitate the acquisition of file cabinets and file folders by some operators. (The average hourly salary – including benefits - for a clerk is estimated at $20. If we assume that the average time to perform these tasks is one-half hour per month, or 6 hours per year, the total cost per operator, per year would be approximately $120 ($20*6)). There is no expectation that the recordkeeping would require operators to hire additional personnel. Neither is there an expectation that the recordkeeping would require operators to acquire new computers or peripherals. PHMSA invites comments on this.

7.2.7 Managing the Distribution Integrity Management Program

Each operator will need to manage its distribution integrity management program. That management will help ensure the proper functioning of each operator's program, including coordination among and between its various parts. In addition to providing oversight and guidance, the managers of each operator's program will serve as points of contact and advocates for the program within the operator's management structure.

Because the program is new, the costs of managing it are unknown and consequently must be estimated. Table 16 presents PHMSA's estimates of the costs of managing the program for large operators, small operators, and master meter and LPG systems, as well as the total cost to the gas distribution industry of managing the integrity management program. The estimates in Table 16 were developed following discussions with gas distribution industry representatives.

PHMSA's estimates assume that the management requirements will be significantly greater in the first year, when the programs are being created, than in subsequent years. For example, PHMSA estimates that large operators will need to devote one-half of a labor year to integrity management program management in the first year, but only one-quarter of a labor year to management in subsequent years.

In total, PHMSA estimates that the cost of DIMP management will be $30.9 million dollars in the first year and $15.5 million in each subsequent year. Of this total, large operators will pay $14.0 million in the first year and $7.0 million in each subsequent year, small operators will pay $7.3 million in the first year and $3.7 million in each subsequent year, and master meter and LPG systems will pay $9.6 million in the first year and $4.8 million in each subsequent year.

TABLE 16. ESTIMATED COSTS OF DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM MANGEMENT

Type of Operator	Number of Operators	Labor Hours per Operator	Labor Rate (Fully loaded cost per labor hour)	Total Annual Cost in Year 1 ($ Million)	Total Annual Cost in Year 2 and On ($ Million)
Large Operators	201	996 in yr. 1; 498 in yrs. 2 & on	$70	$14.0	$7.0
Small Operators	1,090	96 in yr. 1; 48 in yrs. 2 & on	$70	$7.3	$3.7
Master Meter and LPG Systems	8,000	24 in yr. 1; 12 in yrs. 2 & on	$50	$9.6	$4.8
TOTAL				$30.9	$15.5

On a per operator basis, the cost of managing an integrity management program for large operators will be approximately $70,000 in the first year and $35,000 in each subsequent year. The cost for small operators will be approximately $7,000 in the first year and $3,000 in each subsequent year, and the cost for master meter and LPG systems will be approximately $1,000 in the first year and $1,000 in each subsequent year.

PHMSA's estimates may overstate the net additional cost of management attributable to the proposed rule. Currently, operators have activities and programs in place, including leak and damage prevention programs, which will likely be brought under the DIMP umbrella by those operators if the proposed rule is implemented. Those activities and programs, as a consequence, may need less management than they did before. This potential reduction in the cost of managing currently existing activities is not included in PHMSA's estimates.

7.2.8 Total Cost

Table 17 summarizes the costs associated with the proposed rule. In total, PHMSA expects the rule to cost operators $155.1 million in the first year and $104.1 million in the second and subsequent years. Of this total, large operators will pay $86.1 million in the first year and $76.0 million in every year thereafter, small operators will pay $43.4 million in the first year and $18.6 million in every year thereafter, and master meter and LPG systems will pay $25.6 million in the first year and $9.5 million in every year thereafter.

TABLE 17. SUMMARY OF COSTS ASSOCIATED WITH THE DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM

Type of Operator and Cost Category	Total Annual Cost in Year 1 ($ Million)	Total Annual Cost in Year 2 and On ($ Millions)
Large Operators		
Developing program	$36.1	$4.1
Data acquisition and analysis	$36.0	$11.8
Mitigation	---	$53.1
Reporting	Nominal	Nominal
Recordkeeping	Nominal	Nominal
Management	$14.0	$7.0
TOTAL	$86.1	$76.0
Small Operators		
Developing program	$17.8	$1.8
Data acquisition and analysis	$18.3	$7.3
Mitigation	---	$5.8
Reporting	Nominal	Nominal
Recordkeeping	Nominal	Nominal
Management	$7.3	$3.7
TOTAL	$43.4	$18.6
Master Meter and LPG Systems		
Developing program	$12.8	$1.6
Data acquisition and analysis	$3.2	$1.6
Mitigation	---	$1.5
Reporting	Nominal	Nominal
Recordkeeping	Nominal	Nominal
Management	$9.6	$4.8
TOTAL	$25.6	$9.5
GRAND TOTAL	$155.1	$104.1

On a per operator basis, the total cost of an integrity management program for large operators will be approximately $428,000 in the first year and $378,000 in each subsequent year. The cost for small operators will be approximately $40,000 in the first year and $17,000 in each subsequent year, and the cost for master meter and LPG systems will be approximately $3,000 in the first year and $1,000 in each subsequent year.

Based on the total cost estimates for the first and subsequent years, the present value of the costs of the proposed rule calculated over 50 years with a 3% discount rate would be $2.7 billion, while the present value of the proposed rule calculated over 50 years with a 7% discount rate would be $1,484 million.

PHMSA encourages comment on the cost estimates developed for this analysis.

7.3 Comparison of Benefits and Costs

The benefits resulting from the proposed rule are estimated to be $214 million per year. The costs of the proposed rule are estimated to be $155.1 million in the first year and $104.1 million in each subsequent year. Table 18 gives the present values for these estimated benefits and costs over 50 years at 3% and 7% discount rates.

TABLE 18. PRESENT VALUES OF BENEFITS, COSTS, and NET BENEFITS OF THE PROPOSED RULE CALCULATED OVER 50 YEARS (All dollars in millions)

Discount Rate	Benefits	Costs	Net Benefits
3%	$5,506	$2,728	$2,778
7%	$2,953	$1,484	$1,469

As can be seen from Table 18, the estimated present value of net benefits of the proposed rule is positive at each discount rate. At the 3 percent discount rate there appears to be about $2.8 billion in net benefits over the 50-year period, and at 7 percent about $1.5 billion over 50 years.

8. UNCERTAINTY ANALYSES

There are many uncertainties associated with this analysis. To deal with those uncertainties, various assumptions were made. For example, to deal with the uncertainties associated with incidents in the future, it has been assumed that the future will resemble the recent past.

Rather than attempt to detail the impact of each assumption individually, the aggregate impact of the assumptions associated with each of the benefits and costs derived for this analysis is examined below. Because assumptions are made for each benefit and for each cost, looking at their contribution to the total of benefits or costs is one way of assessing the aggregate impact of the assumptions.

Table 19 presents the contributions that (1) each of the benefits addressed in this analysis make to the total present value of the benefits of the proposed rule and (2) each of the costs addressed in this analysis make to the total present value of the costs of the proposed rule.

TABLE 19. IMPACT OF THE EXPECTED BENEFITS ON THE PRESENT VALUE OF BENEFITS AND THE EXPECTED COSTS ON THE PRESENT VALUE OF COSTS FOR THE DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM

Benefit and Cost Categories	Present Value with 3% Discount Rate ($ Million)	Present Value with 7% Discount Rate ($ Million)	Percent of Total When Discount Rate Is 3%	Percent of Total When Discount Rate Is 7%
Benefits				
Reduced reportable incident consequences	$1,544	$828	28%	*
Reduced non-reportable incident consequences	$720	$386	13%	*
Lowered chance of a catastrophic incident	$154	$83	3%	*
Reduced lost gas	$1,955	$1,049	36%	*
Reduced emergency response costs	$283	$152	5%	*
Reduced evacuations	$129	$69	2%	*
Reduced non-gas dig-ins	$695	$373	13%	*
End of existing EFV notification requirement	$26	$14	<1%	*
TOTAL	$5,506	2,954		
Costs				
Developing program	$250	$159	9%	11%
Data acquisition and analysis	$568	$320	21%	22%
Mitigation	$1,495	$777	55%	52%
Reporting	---	---	---	---
Recordkeeping	---	---	---	---
Management	$414	$228	15%	15%
TOTAL	$2,728	$1,484	100%	100%

Note: * = Same as percentage with 3% discount rate.

Reduced lost gas is the most significant contributor, accounting for 28% of the total present value of benefits. With respect to costs, the most significant contributor to the total present value of costs is mitigation, which accounts for 52%-55% of the total present value of costs

8.1 Analyses Excluding Benefits of Reduced Lost Gas and Reduced Losses From High Consequence Events

Assumptions with respect to the benefits attributed to, for example, reduced lost gas or reduced costs associated with low probability/high consequence events, which are uncertain rare events, can be examined for whether they alter the net benefits of the proposed rule if those benefits are not realized.

Reduced lost gas benefits were estimated at $76 million per year. If those benefits are eliminated from the previously estimated annual benefits of $214 million (See Table 18) the present value of expected benefits (discounted at 3 percent) falls from $5,506 million to $3,551 million. This level of benefits is still greater than the 3% present value discounted costs of $2,728 billion. If the reduced benefits of reduced lost gas are discounted at 7 percent, the present value of benefits falls from $2,953 to $1,905 million, which is still greater than the 7% present value, discounted costs of $1,484. With these scenarios there are still positive net benefits without any benefits from reduced lost gas. See Table 20 below.

TABLE 20. PRESENT VALUES OF BENEFITS, COSTS, and NET BENEFITS EXCLUDING BENEFITS OF REDUCED LOST GAS ($76 Million)
(All dollars in millions)

Discount Rate	Benefits	Costs	Net Benefits
3%	$3,551	$2,728	$823
7%	$1,905	$1,484	$421

Based on the analysis in the absence of the $76 million in benefits due to reduced lost gas, it is obvious that eliminating the $5.7 million annual benefits due to reduced losses from high consequence events will not alter the outcome of the analysis. However, we can also examine the effect of eliminating benefits from both reduced gas lost and reduced costs associated with high consequence events. Taking both benefits from the $214 million annual benefits reduces the annual benefits to $132.3 million [$214 million – ($76 million + $5.7 million)]. The discounted present value over 50 years (at 3 and 7 percent) is $3,404 million and $1,826 million respectively, which is still greater than the present value of the respective costs discounted at 3 and 7 percent. There are still positive net benefits without benefits of either reduced lost gas or reduced costs of high consequence events. See Table 21 below.

TABLE 21. PRESENT VALUES OF BENEFITS, COSTS, and NET BENEFITS EXCLUDING REDUCED LOST GAS AND REDUCED LOSSES FROM HIGH CONSEQUENCE EVENTS ($81.7 Million)
(All dollars in millions)

Discount Rate	Benefits	Costs	Net Benefits
3%	$3,404	$2,728	$676
7%	$1,826	$1,484	$345

8.2 Effectiveness Analysis

The benefit-cost analysis in previous sections depended upon making assumptions about the effectiveness of the proposed rule in reducing various components of the societal costs associated with gas distribution systems. For example, the analysis assumes that the rule will reduce 50 percent of the costs associated with reportable incidents and 10 percent of the costs associated with lost gas. The predicted outcome of the analysis in terms of net benefits will vary as the levels of effectiveness vary.

An alternative evaluation of the proposed rule's assumptions, and the robustness of the Department's conclusions, is to determine the overall level of effectiveness in reducing societal costs associated with gas distribution systems that must be attained to cover the estimated costs of the rule. From the benefit analysis earlier in this report the annual societal cost are approximately those illustrated in the table below.

TABLE 22. CONTRIBUTORS TO SOCIETAL COSTS

Incidents and other Contributors to Societal Costs Associated with Gas Distribution	Estimate (Million dollars per year)
Reportable Incidents	87
Non-reportable Incidents	56
High consequence incidents	8
Lost Gas	759
Emergency Response Costs	44
Evacuations	5
Non-Gas Excavations	108
Existing EFV Notification Requirement	1
TOTAL	$1,068

The costs of the proposed rule are estimated to be about $155 million the first year and about $104 in each year thereafter. If there are to be the level of benefits to equal those costs, then the proposed rule would have to be about 14.5 percent ($155/1068 * 100) effective in reducing overall societal costs the first year, and about 9.7 percent (104/1068*100) effective in subsequent years.

9. SUMMARY AND CONCLUSIONS

PHMSA proposes to revise the Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement programs that will better assure the integrity of their pipeline systems. The proposed regulations require distribution pipeline operators to implement an IMP similar to those required for gas transmission pipelines.

The proposed rule is expected to impact 201 local gas utilities with over 12,000 services, 1,090 local gas utilities with 12,000 or fewer services, and 8,000 master meter and LPG systems. The larger local gas utilities are estimated to have over 1 million miles of mains and nearly 55 million services, while the smaller utilities are estimated to have over 100 thousand miles of mains and approximately 5 million services. Master meter and LPG systems are estimated to have 8 thousand miles of mains and 800 thousand services.

The readily monetized benefits resulting from the proposed rule are estimated to be $214 million per year. The monetized benefits include:

- Reductions in the consequences of reportable incidents.
- Reductions in the consequences of non-reportable incidents.
- A reduction in the probability of a major catastrophic incident.
- Reductions in lost natural gas.
- Reductions in emergency response costs.
- Reductions in evacuations.
- Reductions in dig-ins impacting non-gas underground facilities.
- The end of the existing EFV notification requirement.

The costs of the proposed rule are estimated to be $155.1 million in the first year and $104.1 million in each subsequent year. The costs include:

- Development of an IMP.
- Implementation of the IMP (data acquisition and analysis).
- Mitigation of risks.
- Reporting to PHMSA and State regulators.
- Recordkeeping.
- Management of the IMP.

The present value of the monetized benefits of the proposed rule is estimated to be about $5.5 billion calculated over 50 years using a 3% discount rate and about $3.0 billion calculated over 50 years using a 7% discount rate. The present value of the estimated costs of the proposed rule would be expected to be $2.7 billion over 50 years using a 3% discount rate and about $1.5 billion over 50 years using a 7% discount rate. Based on these calculations, the best estimate of the present value of expected net benefits is between $1.5 and $2.8 billion over a 50-year period.

Another conclusion is that for the proposed rule to be cost-effective, the societal costs associated with the risks and hazards associated with gas distribution systems need to be reduced by about 14.5 percent per year on average over a 50-year period.

This economic evaluation suggests that the proposed rule is in the public interest because there are expected net benefits and there is relatively low rate of realized benefits for the proposed rule to be cost effective.

Regulatory Flexibility Analysis
Integrity Management Program for Gas Distribution Pipelines

Introduction

The Regulatory Flexibility Act of 1980 (Public Law 96-354) requires agencies to evaluate the potential effects of their proposed and final rules on small businesses, small organizations, and small governmental jurisdictions. The Regulatory Flexibility Act requires that Federal agencies take small entities' concerns into account when developing, writing, publicizing, promulgating, and enforcing regulations. To this end, the Act requires that agencies detail how they have met these concerns, by including a Regulatory Flexibility Analysis (RFA). An initial RFA, which accompanies a Notice of Proposed Rulemaking (NPRM), must include the following five elements:

1) A description of the reasons why action by the Agency is being considered;
2) A succinct statement of the objectives of, and legal basis for, the proposed rule;
3) A description of and, where feasible, an estimate of the number of small entities to which the proposed rule would apply;
4) A description of the proposed reporting, recordkeeping, and other compliance requirements of the proposed rule, including an estimate of the classes of small entities that would be subject to the requirements and the type of professional skills necessary for preparing the report or record; and
5) Identification, to the extent practicable, of all Federal rules which may duplicate, overlap, or conflict with the proposed rule.

A discussion of these requirements follows.

1. A description of the reasons why action by the Agency is being considered.

In 2004, the U.S. Department of Transportation (DOT) Inspector General (IG) pointed out that recent accident trends for gas distribution pipelines were unfavorable and suggested that the application of integrity management principles could help improve the safety of distribution pipelines.

The IG recommended to Congress[57] that DOT define an approach for requiring operators of distribution pipeline systems to implement some form of integrity management or enhanced safety program with elements similar to those required in hazardous liquid and transmission pipeline integrity management programs (IMPs). The Appropriations Committee then asked PHMSA "to report to the House and Senate Committees on Appropriations by May 1, 2005, detailing the extent to which integrity management program elements may be applied to the natural gas distribution pipeline industry in order

[57] "Progress and Challenges in Improving pipeline Safety," Statement of the Honorable Kenneth M.Mead, Inspector General, Department of transportation, before the Committee on energy and Commerce, Subcommittee on Energy and Air Quality, U.S. House of Representatives, July 20, 2004.

to enhance distribution system safety."[58] PHMSA submitted the report "Assuring the Integrity of Gas Distribution Pipeline Systems" to Congress in June 2005, which describes the program used to identify opportunities for improving the safety of distribution pipeline systems.

PHMSA proceeded to develop the IMP for gas distribution pipelines in two phases. Phase 1 identified the nature of requirements that might be imposed and any additional guidance or consensus standards that might be needed to assist operators in implementing any integrity management requirements. Phase 2 included development of appropriate requirements by PHMSA and preparation of guidance/standards by appropriate bodies. PHMSA determined that in order to address safety threats to distribution pipelines and develop a sensible strategy to reduce threats, the Agency needed to involve a number of key stakeholder groups, including State and Federal regulators, representatives from the spectrum of distribution operators, interested members of the public, and representatives of our Nation's fire service. The stakeholders agreed with the DOT IG and Congress's recommendations and concluded the current pipeline safety regulations (49 CFR Part 192) do not include a risk-based integrity management process for gas distribution pipelines and that it would be appropriate to modify the regulations to incorporate such a requirement.[59] The study group gathered and analyzed data to help focus the effort and ultimately identify options for attaining improved safety.

2. A succinct statement of the objectives of, and legal basis for, the proposed rule.

In response to the mandate concerning IMPs for distribution systems contained in The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (Public Law No: 109-468, Dec. 29, 2006), also known as the PIPES Act. PHMSA is initiating this rulemaking. PHMSA is extending its integrity management approach to the largest segment of the Nation's pipeline network – the distribution systems that directly serve homes, schools, businesses, and other natural gas consumers. Beginning in 2000, the agency promulgated regulations requiring operators of hazardous liquid pipelines (49 CFR 195.452, published at 65 FR 75378 and 67 FR 2136) and gas transmission pipelines (49 CFR 192, Subpart O, published at 68 FR 69778) to develop and follow individualized IMPs, in addition to PHMSA's core pipeline safety regulations.

PHMSA proposes to require operators of gas distribution pipelines to develop and implement IMPs that will better assure the integrity of their pipeline systems. Each IMP must contain the following elements:

- Improving knowledge of the system's infrastructure.
- Identifying threats (existing and potential).
- Evaluating and prioritizing risks.
- Identifying and implementing measures to mitigate risks.

[58] House of Representatives report 108-792, November 20, 2004.
[59] "Integrity Management for Gas Distribution, Report of Phase 1 Investigations", prepared by Joint Work/Study Groups, December 2005, U.S. DOT/PHMSA - Report: DIMP Phase 1, Doc. Number: RSPA-2004-19854-70, available at http://dmses.dot.gov/docimages/p84/388302.pdf

- Measuring performance, monitoring results, and evaluating effectiveness.
- Periodic re-evaluation and improvement.
- Reporting results..

All of the above elements pertain to distribution operators with the exception of master meter and LPG distribution systems. The IMPs of master meter and LPG systems must include all of the elements listed above except (1) evaluating and prioritizing risks and (2) reporting results.

In addition, the proposed rule requires the installation of EFVs, where practicable, on all new and renewed single-family residential services operating at at least 10 psig. Master meter and LPG systems would be exempt from this requirement. The proposed mandatory installation renders the current customer EFV notification requirement (see 49 CFR 192.383) moot. Consequently, the proposed rule would eliminate that requirement.

3. A description of and, where feasible, an estimate of the number of small entities to which the proposed rule would apply.

The proposed rule would affect operators of (1) local gas distribution utilities and (2) master meter and LPG systems. The number of operators impacted by the proposed rule is unknown and must be estimated. Furthermore, the size of the operators impacted by the proposed rule is also unknown and, consequently, must also be estimated.

The impacted operators all belong to North American Industry Classification System (NAICS) 221210, Natural Gas Distribution. In accordance with size standards published by the Small Business Administration, a business with 500 or fewer employees is considered a small entity in this NAICS.[60]

PHMSA expects 1,291 local gas distribution utilities and 8,000 master meter and LPG systems to be impacted by the proposed rule. Based on information from Dun & Bradstreet (August 2006) on firms in NAICS 221210, PHMSA estimates that 78% of the local gas distribution utilities have 500 or fewer employees. That is, PHMSA estimates that 1,007 of the local gas distribution utilities impacted by the proposed rule will have 500 or fewer employees. Furthermore, PHMSA assumes that all 8,000 master meter and LPG systems will have 500 or fewer employees. Thus, in total, PHMSA expects that 9,007 small entities will be impacted by the proposed rule.

The 1291 local gas distribution utilities were divided in the analysis performed by PHMSA into those with greater than 12,000 services and those with 12,000 or fewer services. A total of 201 operators fell into the first category, while 1,090 operators fell into the second. Costs were separately estimated for each category.

For this analysis, none of those with greater than 12,000 services are assumed to be small entities as defined by the SBA. That is, the 1,007 local gas distribution utilities that are

[60] http://www.sba.gov/size/sizetable2002.pdf.

small entities are all assumed to have 12,000 or fewer services. PHMSA estimates that the proposed rule will cost each operator in this category, on average, approximately $40,000 in the first year and $17,000 in each subsequent year.

PHMSA estimates that the proposed rule will cost each of the estimated 8,000 master meter and LPG systems that it impacts, on average, approximately $3,000 in the first year and $1,000 in each subsequent year. PHMSA does not have information on the operators' revenues and cannot, therefore, estimate what percent of revenues the cost represents. PHMSA requests comment on the impact on these operators.

There is currently no case law that identifies the "trigger" levels of "significant economic impact," or "substantial number of small entities." However, because the purpose of the analysis is to aid the decision maker in resolving regulatory issues affecting small entities, it is SBA's opinion that any rulemaking generating the interest of a significant number of small entities warrants the application of the RFA's analysis tools.[61] PHMSA prepared the analysis required by the Regulatory Flexibility Act.[62] As a consequence of the foregoing, the proposed rule is expected by PHMSA to impact a substantial number (9,007) of small entities. The breakdown of these between those that are very small operations and those that are small by SBA definitions is unknown. Few, if any, of the small gas distribution utilities with 12,000 or fewer services are expected to be very small operations. Almost all of the master meter and LPG systems will be small.. For example, while a master meter or LPG system serving a small trailer park might potentially be a very small operation, master meter and LPG systems operated by public housing authorities or by colleges and universities will not be. The proposed rule could result in a significant adverse economic impact for at least some of those small entities, since for some of the small operators the costs associated with the proposed rule may be significant.

<u>Alternate proposals for small businesses</u>: The RFA directs agencies to establish exceptions and differing compliance standards for small businesses, where it is possible to do so and still meet the objectives of applicable regulatory statutes.

For the proposed distribution IMP rule, PHMSA will be taking a number of steps to meet its safety objectives without unduly burdening small business. PHMSA's actions include the following:

- PHMSA will not require master meter and LPG systems to comply with all of the requirements of the proposed rule. PHMSA feels that it is possible to do this without compromising safety because of the nature of the master meter and LPG systems.
- PHMSA is preparing guidance to help master meter and LPG systems implement certain requirements of gas integrity management.

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[61] A Guide for Government Agencies, "How to Comply with the Regulatory Flexibility Act." See http://www.fws.gov/policy/library/rgSBAGuide.pdf

[62] "A Guide for Government Agencies. How to Comply with the Regulatory Flexibility Act." Implementing the President's Small Business Agenda and Executive Order 13272, May 2003, p.17.

- PHMSA would be willing to consider extending the limitations on the applicability of the integrity management requirements that it proposes for master meter and LPG systems to other operators if reasonable criteria can be defined to identify operators for which such limitation are appropriate. This willingness to extend the limitations is explicitly stated in the preamble to the proposed rule. Industry is encouraged by PHMSA to comment on this.
- PHMSA will modify its *Guidance Manual for Operators of Small Natural Gas Systems*[63] to include information that can help small entities understand and comply with the distribution integrity management program requirements if the proposed rule is adopted. The manual has been developed by PHMSA to provide an overview of pipeline compliance responsibilities under the federal pipeline safety regulations for the non-technically trained person who operates a master meter system, a small municipal system, or small independent system. Similarly, PHMSA will also modify its *Guidance Manual for Operators of Small LP Gas Systems* if the proposed rule is adopted.[64]

In addition to the foregoing, industry is undertaking a number of initiatives that will help small entities comply with the proposed rule, including the following:

- The Gas Pipeline Technology Committee (GPTC) will prepare guidance material to assist operators, including small distribution system operators, with development of an integrity management program.

The American Public Gas Association (APGA) Security and Integrity Foundation (SIF) will develop a model Distribution Integrity Management Program to assist small utilities in developing integrity management programs meeting the requirements of the proposed rule. The end product will be a simple and handy risk-based integrity management program.

4. A description of the proposed reporting, recordkeeping, and other compliance requirements of the proposed rule, including an estimate of the classes of small entities that would be subject to the requirements and the type of professional skills necessary for preparing the report or record.

The proposed rule would require that each operator impacted by that rule keep certain records. At a minimum, those records must include:

- A written integrity management program.
- Documents supporting threat identification.
- A written procedure of ranking threats.
- Documents supporting any decision, analysis, or process developed and used to implement and evaluate each element of the integrity management program.

[63] The Guidance Manual for Operators of Small Natural Gas Systems can be found on the PHMSA website at http://ops.dot.gov/regs/small_ng/SmallNaturalGas.htm.
[64] The Guidance Manual for Operators of Small LP Gas Systems can be found on the PHMSA website at http://ops.dot.gov/regs/small_lp/SmallLPGas.htm.

- Records identifying changes made to the integrity management program or its elements, including a description of the changes and the reasons they were made.

Operators must keep the records for the useful life of the pipeline.

PHMSA estimates some of the required records will be kept electronically, while others will be kept on paper. In the case of those kept electronically, the required recordkeeping will necessitate a company clerk entering data and in some cases, scanning materials. In the case of the paper records, the required recordkeeping will necessitate a company clerk placing materials in file folders, storing them, and retrieving files, when needed. It may also necessitate a system for signing materials in-and-out. Finally, in some cases, physical recordkeeping may necessitate the acquisition of file cabinets and supplies by some operators. There is no expectation that the recordkeeping would require operators to hire additional personnel. Neither is there an expectation that the recordkeeping would require operators to acquire new computers or peripherals. PHMSA assumes that the proposed rule does not add significantly to the distribution operators' current recordkeeping requirements, particularly since the proposed rule would remove the EFV customer notification requirement. Currently, on average, the EFV burden is estimated at almost 18 hours and $905 dollars per operator.

5. Identification, to the extent practicable, of all Federal rules which may duplicate, overlap, or conflict with the proposed rule.

There are no related rules or regulations issued by other departments or agencies of the Federal Government.