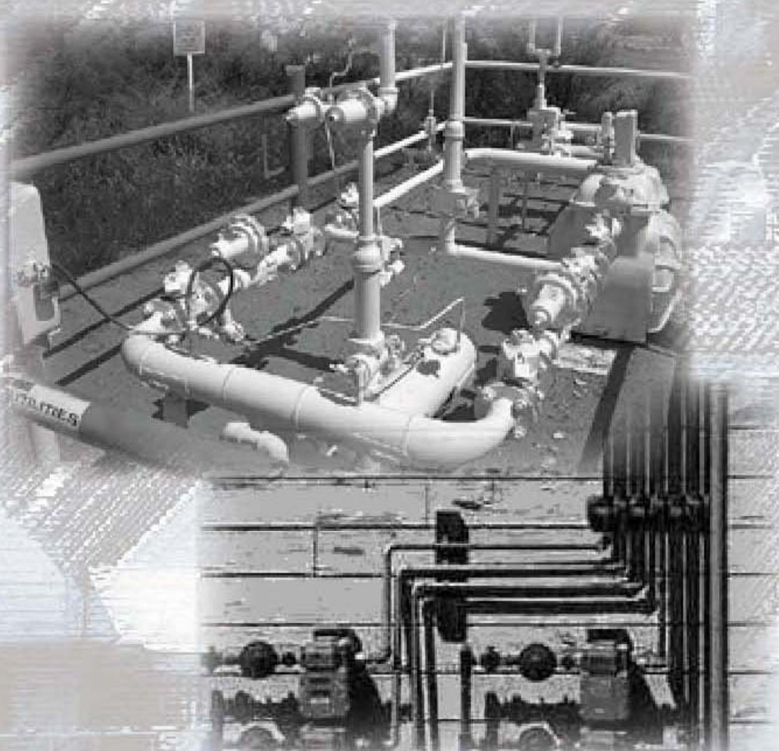
Integrity Management for Gas Distribution



Report of Phase 1 Investigations

December 2005

Prepared by joint work/study groups including representatives of:
- Stakeholder Public
- Gas Distribution Pipeline Industry
- State Pipeline Safety Representatives
- Pipeline and Hazardous Materials Safety Administration

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Acronym List

AGF – American Gas Foundation
ASME – American Society of Mechanical Engineers
ASTM – American Society of Testing and Materials
BAA – Broad Agency Announcement
DIMP – Distribution Integrity Management Program
DOT – Department of Transportation
EFV – Excess Flow Valve
GPTC – Gas Piping Technology Committee
IAFC – International Association of Fire Chiefs
IG – Inspector General
IM – Integrity Management
IMP – Integrity Management Program
LDC – Local Distribution Company
LEAKS – Leak Management Program Consisting of: Locate, Evaluate, Act, Keep Records, and Self-Assess
NAPSR – National Association of Pipeline Safety Representatives
NARUC – National Association of Regulatory Utility Commissioners
PHMSA – Pipeline and Hazardous Materials Safety Administration
PIM – Pipeline Integrity Management (transmission)
PSIA – Pipeline Safety Improvement Act of 2002
R&D – Research and Development
SMYS – Specified Minimum Yield Strength

Executive Summary

The Pipeline and Hazardous Materials Safety Administration (PHMSA) has implemented integrity management requirements for hazardous liquid and gas transmission pipelines. No similar requirements presently exist for gas distribution pipelines, but observers have suggested that they are needed. Four multi-stakeholder work/study groups were established to collect and analyze available information and to reach findings and conclusions to inform future work by the PHMSA relative to implementing integrity management principles for gas distribution pipelines. The groups have concluded that current pipeline safety regulations (49 CFR Part 192) do not now convey the concept of a risk-based distribution integrity management process and that it would be appropriate to modify the regulations to do so.

The groups found that the most useful option for implementing distribution integrity management requirements is a high-level, flexible federal regulation, in conjunction with implementation guidance, a nation-wide education program expected to be conducted as part of implementing 3-digit dialing for One-Call programs, and continuing research and development.

Differences between gas distribution pipeline operators, and the pipeline systems they operate, make it impractical simply to apply the integrity management requirements for transmission pipelines to distribution. The significant diversity among gas distribution pipeline operators also makes it impractical to establish prescriptive requirements that would be appropriate for all circumstances. Instead, the groups concluded that it would be appropriate to require that all distribution pipeline operators, regardless of size, implement an integrity management program including seven key elements, namely that each operator:

1. Develop and implement a written integrity management plan.
2. Know its infrastructure.
3. Identify threats, both existing and of potential future importance.
4. Assess and prioritize risks.
5. Identify and implement appropriate measures to mitigate risks.
6. Measure performance, monitor results, and evaluate the effectiveness of its programs, making changes where needed.
7. Periodically report a limited set of performance measures to its regulator.

Since entire distribution systems would be covered by the distribution integrity management plan, there is no need to identify high consequence areas or identified sites as part of the plan as was required for transmission pipelines.

The Executive Steering Group considers that it should be possible to develop and promulgate a regulation within about two years so that distribution operators can develop integrity management plans during 2008 and begin implementing those plans in about 2009. Guidance will be needed to assist operators in implementing the high-level regulatory provisions in their particular circumstances. Detailed guidance will be needed

for the smallest operators, who have limited resources for developing customized programs.

The groups concluded that excavation damage poses the most significant single threat to distribution system integrity. Reducing this threat requires affecting the behavior of persons not subject to the jurisdiction of pipeline safety authorities (e.g., excavators working for other than pipeline facility owners/operators). Some states have implemented effective comprehensive damage prevention programs that have resulted in significant reductions in the frequency of damage from excavation. Effective programs include nine elements:

1. Enhanced communication between operators and excavators
2. Fostering support and partnership of all stakeholders in all phases (enforcement, system improvement, etc.) of the program
3. Operator's use of performance measures for persons performing locating of pipelines and pipeline construction
4. Partnership in employee training
5. Partnership in public education
6. Enforcement agencies' role as partner and facilitator to help resolve issues
7. Fair and consistent enforcement of the law
8. Use of technology to improve all parts of the process
9. Analysis of data to continually evaluate/improve program effectiveness

Not all states have implemented such programs. Federal legislation is likely needed to support the development and implementation of such programs by all states. Work on this legislation can begin immediately. This represents the greatest single opportunity for distribution pipeline safety improvements.

The groups concluded that excess flow valves (EFVs) can be a valuable incident mitigation option, but that a federal mandate for their installation would be inappropriate. (All groups agreed with this conclusion, although some individual members favored a mandate). Analysis of operational experience demonstrated that when properly specified and installed, the valves function as designed; they successfully terminate gas flow under accident conditions and only rarely malfunction to prevent flow when an accident has not occurred. A regulatory provision that would require that operators consider certain risk factors in deciding when to install EFVs would be appropriate. Guidance would be useful concerning the conditions under which EFVs are not feasible (e.g., low pressures, gas constituents inconsistent with valve operation) and concerning risk factors indicating when their installation might be appropriate.

The groups also concluded that management of gas leaks is fundamental to successful management of distribution risk, and an effective leak management program is thus a vital risk control practice. Effective programs include the following elements:

1. **_L_ocate** the leak,
2. **_E_valuate** its severity,

3. ***A*ct** appropriately to mitigate the leak,
4. ***K*eep** records, and
5. ***S*elf-assess** to determine if additional actions are necessary to keep the system safe.

This effort concluded, as did the American Gas Foundation before it[1], that distribution pipelines are safe. Incidents continue to occur, but their frequency has been reduced. There is room for improvement. Implementing integrity management, consistent with the findings and conclusions of the work/study groups, should help achieve additional improvement.

1. Structure of This Report

This report covers the work of four work/study groups, as described in the next section. The main body of the report (Sections 2 through 5) describes the context in which this work was performed and the key overall findings and conclusions. The appendices present:

- A: a list of participants,
- B: the complete list of findings and conclusions from all four work/study groups,
- C: the complete list of path forward actions suggested by the four groups, and
- D: independent comments on excess flow valves from the International Association of Fire Chiefs and related organizations.

The separate reports of each of the four work/study groups are included as attachments to this report.

2. Introduction

Background

The Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published new rules requiring "integrity management" programs for hazardous liquid pipelines in 2000[2] and 2002[3] and for natural gas transmission pipelines in 2003.[4] Under these rules, operators of hazardous liquid and gas transmission pipelines were required to identify the threats to their pipelines, analyze the risk posed by these threats, collect information about the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline accidents could occur.

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[1] American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure," January, 2005.
[2] 65 FR 75378, December 1, 2000.
[3] 67 FR 2136, January 16, 2002.
[4] 68 FR 69778, December 15, 2003.

The initial implementation of these integrity management regulations has resulted in the identification and repair of many conditions that could potentially have resulted in pipeline accidents had they not been addressed. The early results of these programs led PHMSA to consider whether a similar regulatory approach would be appropriate for gas distribution pipelines.

Distribution pipelines are different from other pipelines. Hazardous liquid and gas transmission pipelines traverse long distances (including many rural areas), are generally of large diameter (up to 48 inches), are comprised primarily of steel pipe, typically operate at relatively high stress levels, and have few branch connections. Failures of hazardous liquid pipelines can result in significant environmental contamination. Failures of gas transmission pipelines usually occur as a catastrophic rupture of the pipeline, caused by the high pressure of the contained gas.

Distribution pipeline systems exist in restricted geographical areas that are predominantly urban/suburban, because the purpose of these pipelines is to deliver natural gas to end users – residential, commercial, industrial, institutional, and electric generation customers. Distribution pipelines are generally small in diameter (as small as 5/8 inch), and are constructed of several kinds of materials including a significant percentage of plastic pipe. Distribution pipelines also have frequent branch connections, since service lines, providing gas to individual customers, branch off of a common "main" pipeline, typically installed under the street. The dominant cause of distribution incidents is excavation damage with third party damage being the major contributor to these incidents. Other than as caused by excavation damage, distribution pipeline failures almost always involve leaks, rather than ruptures, because the internal gas pressure is much lower than for transmission pipelines. These differences mean that many of the tools and techniques used in integrity management programs for other types of pipelines are not appropriate or cannot be used for distribution pipelines.

American Gas Foundation Study

In considering whether and how integrity management principles could be applied to distribution pipelines, the first question that was addressed was whether performance supported the need for additional regulations. The American Gas Foundation (AGF) undertook a study[5] in 2003-2004 to characterize the state of distribution pipeline safety. This study analyzed the safety performance of gas distribution pipeline systems from 1990 to 2002 as represented by the number of incidents reported to PHMSA by operators during that period.[6]

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[5] American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure," January, 2005.
[6] 49 CFR 191.3 defines an incident as an event that involves a release of gas from a pipeline and (1) a death or (2) a personal injury necessitating in-patient hospitalization or (3) that results in estimated property damage of $50,000 or more. 49 CFR 191.9 requires operators of distribution pipelines to submit written reports of all incidents meeting these criteria.

The AGF study compared the number of incidents reported for gas transmission pipelines to those reported for distribution pipelines. Direct comparison of reported incident totals can be misleading, however, since there are many more miles of distribution pipelines than there are transmission pipelines (approximately 1.9 million miles of distribution pipeline compared to approximately 300,000 miles of transmission pipeline[7]). The AGF study allowed for comparison by "normalizing" the incident statistics for both types of pipelines by considering the number of incidents reported per 100,000 miles of in-service pipeline.

The AGF study found that the total number of incidents reported per 100,000 miles was generally less for distribution pipelines than that reported for gas transmission pipelines over the same period. There was no statistically-significant trend (i.e., neither increase nor decrease) in the number of incidents per year for either type of pipeline.

The AGF study also found that the number of incidents that resulted in death or injury (called "serious incidents" within the study) was approximately the same for both transmission and distribution pipelines over the study period. The study found a statistically significant downward trend in the number of serious incidents for both types of pipelines.

The AGF study thus demonstrated that the safety performance of distribution pipelines is good, comparable to that of gas transmission pipelines. The study did not show, however, that the level of safety of distribution pipelines was so great as to preclude the need for a new regulatory approach.

Origins of the Current Study

In 2004, the Department of Transportation (DOT) Inspector General (IG) suggested that application of integrity management (IM) principles could help improve the safety of distribution pipelines. In testimony before Congress in July 2004[8], the IG noted that recently-issued rules had required that operators of hazardous liquid and gas transmission pipelines implement integrity management plans (IMP), but that no such requirement had been imposed on operators of distribution pipelines. The IG acknowledged that a reason why distribution pipeline operators had been excluded from the requirements applicable to operators of gas transmission pipelines was that smart pigs could not be used to inspect distribution pipeline systems. (Such inspections were a principal element of the IM requirements for transmission pipelines). The IG concluded, however, that there was no reason that other elements of IM could not be implemented for distribution pipelines.

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[7] 2003 values reported on the Office of Pipeline Safety web site, http://ops.dot.gov/stats/GTANNUAL2.HTM.

[8] "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.

The IG's testimony recommended that DOT should 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 gas transmission pipeline integrity management programs. The Appropriations Committee asked PHMSA "to report to the House and Senate Committees on Appropriations by May 1, 2005, detailing the extent to which integrity management plan [IMP] elements may be applied to the natural gas distribution pipeline industry in order to enhance distribution system safety."[9]

PHMSA conducted a public meeting on December 16, 2004, in Washington, DC, to solicit comments from all stakeholders on ways in which distribution pipeline integrity might be improved through application of IM principles. Comments made during this meeting emphasized the differences between distribution pipeline systems and those for gas transmission. These differences make it impractical to apply the gas transmission IM requirements to distribution pipelines directly. Comments at the meeting also noted that there is significant diversity among operators of distribution pipeline systems and among the systems they operate, meaning that any new requirements addressing distribution pipeline operators needed to incorporate a high degree of flexibility.

Following the public meeting, PHMSA embarked on a multi-phased effort intended to develop an approach that will address the three elements of the strategy described by the DOT Inspector General:

- understand the infrastructure,
- identify and characterize the threats, and
- determine how best to manage the known risks (prevention, detection and mitigation).

This effort was described in PHMSA's report to Congress, submitted in response to the direction in the Appropriations Committee's report.[10] Phase 1 was described as working with a number of groups comprised of state pipeline safety regulators, pipeline operators, and representatives of the public to seek out additional information about the issues affecting distribution system integrity. This report documents the results of the Phase 1 investigations.

Phase 1 Program Structure

Most distribution pipelines in the United States are regulated by state pipeline safety agencies. It was important to involve state pipeline safety regulators and operators of distribution pipelines in the Phase 1 program, in order to tap their expertise and help assure that conclusions were practical. The Phase 1 effort was designed to involve representatives of state pipeline safety agencies, representatives of distribution pipeline

[9] House of Representatives Report 108-792, November 20, 2004.
[10] Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, Department of Transportation, "Assuring the Integrity of Gas Distribution Pipeline Systems: A Report to the Congress," May 2005.

owners (both investor-owned and municipal agencies), and members of the interested public. Representatives of PHMSA also participated.

Management oversight was provided by an Executive Steering Group, consisting of state regulatory commissioners, industry executive managers, and members of the public. Day-to-day coordination was by a Coordinating Group that included managers from state agencies and the industry trade associations (American Gas Association and American Public Gas Association). The principal investigations were conducted by four work/study groups:

- Strategic Options Group – evaluating strategic approaches to implementing integrity management elements for distribution pipelines
- Risk Control Practices Group – evaluating existing risk control practices, required and/or implemented voluntarily by operators, and the adequacy of existing regulations and guidance
- Excavation Damage Prevention Group – evaluating means to reduce the frequency of damage from excavation near pipelines, which is the predominant cause of distribution pipeline incidents
- Data Group – evaluating existing data on incidents and leaks to identify factors important in preventing distribution incidents and correlating information from surveys of the efficacy of excess flow valves as a risk mitigation tool

The groups conducted their investigations in parallel, to allow this program to be completed promptly (work began in March 2005). Information was exchanged among the groups as needed. Each group prepared a report documenting its work, and these reports are included as attachments to this report. The responsibilities of each work/study group are described in more detail in the May, 2005, PHMSA Report to Congress and in the Action Plan that was included in that report.

The findings and conclusions of each work/study group are presented in their individual reports (which are attached to this report). Inconsistencies or conflicts between the findings of individual groups were addressed by the Coordinating Group. The resulting key findings of the overall program are described in the sections of this report that follow. In the event conflicting statements exist between the work/study group reports and the main body, the information in the main body prevails. The work/study groups also identified, and documented in their reports, a number of actions that would be appropriate for future work as PHMSA and industry prepare to implement an integrity management approach for distribution pipelines. The key elements of this path forward are also described in this summary report.

The members of the groups involved in Phase 1 provide this report to support actions by PHMSA and industry as they proceed with subsequent phases. This summary report has been prepared to make the findings and conclusions readily available for all stakeholders who will be involved in implementing integrity management principles for distribution pipelines.

Review by PHMSA Advisory Committees

The status of this work was reviewed with the Technical Pipeline Safety Standards Committee and the Technical Hazardous Liquid Pipeline Safety Standards Committee, meeting in joint session, on December 13, 2005. The hazardous liquid pipeline committee was included in this review, because the findings regarding federal legislation to advance damage prevention programs will affect all types of pipelines.

The committees supported the general concepts reflected by the product of this effort, recognizing that PHMSA would proceed with rulemaking based on these concepts. Members expressed concern about the imposition of a complex federal requirement on small pipeline operators, including master meter operators, and agreed that additional clear guidance will be needed to facilitate their compliance.

3. Key Findings

Each work/study group reached a number of findings and conclusions about the areas covered by their investigations. A complete list of the group findings is presented in Appendix B to this report. Additional discussion, including further explanation by the groups regarding their findings and conclusions, can be found in the individual group reports, which stand alone but are attached to this report for the reader's convenience.

Each work/study group was asked to identify its "key" findings for purposes of this summary report. These key findings address a number of issues that will be important as further work is undertaken to enhance the integrity management approach for distribution pipelines. These issues are discussed here, along with the key findings that relate to each. This presentation is intended to allow the reader to gain an overview of the important issues. It must be emphasized that, although the work/study groups have identified these as their most important findings, all group findings have importance. Future work should consider all group findings and conclusions.

National Focus of Integrity Management Efforts (Threats)

The integrity management process begins with consideration of what is important to assure pipeline safety, that is, what are the threats to integrity? Understanding the threats is the first step in identifying the appropriate actions to assure integrity. The PHMSA collects data on threats affecting pipelines through incident reports. Operators must characterize each incident they report as being in one of eight categories. The categories are:

Corrosion	Material or Welds
Natural Forces	Equipment
Excavation	Operations
Other Outside Force Damage	Other

These threat categories are appropriate as a foundation for integrity management programs. They represent broad categories. Each can be further subdivided into specific threats. For example, corrosion can be internal or external corrosion. It can be general corrosion or localized pitting. Where appropriate, operators will need to evaluate their threats at this finer level of detail to identify and implement appropriate responsive actions. However, the general categories, matching the current data collection requirements, are appropriate categories for integrity threats on a national basis.

The Data Group evaluated available historical data to identify trends. For distribution pipelines, excavation damage is the predominant cause of reported incidents. Corrosion is the major cause of leaks, but a small fraction of incidents result from corrosion. The Data Group reached a key finding concerning this review of available data:

> *While a decreasing trend in the rate of reportable distribution incidents resulting in fatalities and injuries, including incidents caused by outside force damage, exists for the preceding 13-years, no statistically significant trend was identified for total reportable distribution incidents for that same period.*

While this conclusion is encouraging, it supports the need to explore new requirements for integrity management that will help reduce the occurrence rate of all incidents.

Regulatory Needs

The major question, then, is what kind of requirements would be most appropriate to implement an integrity management approach for distribution pipelines? This question was considered by the Risk Control Practices Group and the Strategic Options Group.

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. Some operators are very small, such as master meter operators serving only a few customers. Many operators serve from 100 and 10,000 customers, and a sizable majority of these operators are municipal agencies.

The pipeline systems that these operators manage are very diverse. Larger systems, in areas where gas service has been available for many years, can include thousands of miles of pipeline of various materials and ages. Systems in areas where gas service has only been available in recent years can be more uniform, consisting of one or a few types of pipe with similar fittings and connections installed using uniform procedures. The smallest systems, such as many master meter systems, may include a limited amount of pipeline, of one material, and all installed at the same time. 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.

The Risk Control Practices Group examined existing federal regulations and the effect they are having, to determine if there were any gaps that would need to be filled by any new integrity management regulations. The group reached a key finding in this area:

> *Current design, construction, installation, initial testing, corrosion control, and operation and maintenance regulations should be effective in providing for integrity of the distribution facilities that are being installed today.*

This conclusion assures us that current requirements are adequate to "build in" necessary safety for new distribution pipeline systems. New integrity management requirements, then, can focus on improving safety for existing systems and assuring that the built-in level of safety is maintained for new pipelines.

The Strategic Options Group considered the form in which new requirements implementing integrity management would be most useful. The group reached two key findings in this area:

> *The most useful option for implementing distribution integrity management requirements is a high-level, flexible federal regulation that excludes no operators, in conjunction with implementation guidance, a nation-wide education program expected to be conducted as part of implementing 3-digit dialing for one-call programs, and continuing research and development.*
>
> *A small number of elements are all that is needed to describe the basic structure of a high-level, flexible federal regulation addressing distribution integrity management. These elements are:*
> - *Development of an integrity management plan*
> - *Know your infrastructure*
> - *Identify threats (existing and potential)*
> - *Assess and prioritize risk*
> - *Identify and implement measures to mitigate risks*
> - *Measure performance, monitor results, and evaluate effectiveness*
> - *Report results*

Finally, the Risk Control Practices Group reached a key finding regarding the necessary scope of any new integrity management requirements.

> *Since the entire distribution system will be covered by the proposed distribution integrity management program (DIMP) plan, there is no need to identify high consequence areas or identified sites as part of the DIMP plan.*

This means that integrity management requirements for distribution pipelines can be both simpler and more broadly applied than the requirements applicable to other pipelines.

For hazardous liquid and gas transmission pipelines, it was necessary to identify high consequence areas – those locations in which a pipeline accident could have the greatest effect. The focus of integrity management requirements for those pipelines was then on the identified areas. For distribution pipelines, high consequence areas need not be defined, and integrity management requirements will affect the entire pipeline system.

Guidance

Historically, guidance developed by a consensus process has been used by operators to assist them in implementing most regulatory requirements. The Gas Piping Technology Committee (GPTC) has developed and maintains a guideline addressing federal requirements applicable to distribution pipeline systems. The American Society of Mechanical Engineers (ASME) and the American Society of Testing and Materials (ASTM) have also developed consensus standards addressing specific technical issues within their areas of expertise that are important in implementing safety requirements. In addition, DOT, through the Transportation Safety Institute (TSI), maintains a small operator's handbook that provides guidance for operators to help assure compliance with the regulations even for operators who lack the resources to develop compliance plans of their own.

High-level, flexible requirements for integrity management will mean that operators will face many choices in deciding what actions to take. Such choices can be facilitated by providing additional guidance that will assist the operators and help to assure that integrity management activities are appropriate for particular circumstances.

The Risk Control Practices Group reached two key findings in this area:

> *The PHMSA plan for a "high level, risk-based, performance-oriented Federal regulation"*[11] *that requires a specific distribution IMP is supported by the fact that (a) the elements necessary to implement a distribution IMP have been identified; (b) the threats have been identified; and (c) methods exist for operators to develop the elements. Operators may need additional guidance materials.*
>
> *The Gas Piping Technology Committee should develop guidance to assist operators in determining (a) which threat prioritization methods, (b) which risk control practices, and (c) which performance measures are most appropriate for their risk control program.*

These findings provide assurance that the foundation for distribution integrity management requirements is firm, and suggest areas in which additional guidance would be useful. Special attention will likely need to be given to the needs of the smallest operators, who lack the resources to develop integrity management plans on their own.

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[11] "Assuring the Integrity of Gas Distribution Pipeline Systems," Report to the Congress, May 2005, Submitted by Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, p. 3.

Preventing Excavation Damage

Excavation damage is the single most significant cause of incidents on distribution pipeline systems. Many, perhaps most, incidents that result from excavation damage occur immediately, at the time the damage is inflicted. Thus, reducing incidents caused by this threat requires that the threat itself be reduced, i.e., that damage be prevented in the first place.

The significance of this threat led to the establishment of a work/study group dedicated specifically to considering ways in which excavation damage could be reduced. Reducing the frequency of excavation damage requires changes in behavior by persons who are not regulated by pipeline safety authorities, that is, contractors and others who perform excavation. Practical actions that operators can implement can have only limited effectiveness in reducing the frequency of damage events. It would be impractical to require that distribution pipeline operators monitor and restrict the activities of those conducting excavations near their pipelines. Instead, action is needed on a broader basis than simply additional regulation imposed on pipeline operators.

The Excavation Damage Prevention Group reached four key findings in this area:

> *Excavation damage poses by far the single greatest threat to distribution system safety, reliability and integrity; therefore excavation damage prevention presents the most significant opportunity for distribution pipeline safety improvements.*
>
> *States with comprehensive damage prevention programs that include effective enforcement have a substantially lower probability of excavation damage to pipeline facilities than states that do not. The lower probability of excavation damage translates to a substantially lower risk of serious incidents and consequences resulting from excavation damage to pipelines.*
>
> *A comprehensive damage prevention program requires nine important elements be present and functional for the program to be effective. All stakeholders must participate in the excavation damage prevention process. The elements are:*
>
> 1. *Enhanced communication between operators and excavators*
> 2. *Fostering support and partnership of all stakeholders in all phases (enforcement, system improvement, etc.) of the program*
> 3. *Operator's use of performance measures for persons performing locating of pipelines and pipeline construction*
> 4. *Partnership in employee training*
> 5. *Partnership in public education*
> 6. *Enforcement agencies' role as partner and facilitator to help resolve issues*
> 7. *Fair and consistent enforcement of the law*
> 8. *Use of technology to improve all parts of the process*
> 9. *Analysis of data to continually evaluate/improve program effectiveness*

> *Federal Legislation is needed to support the development and implementation of damage prevention programs that include effective enforcement as a part of the state's pipeline safety program. This is consistent with the objectives of the state pipeline safety programs, which are to ensure the safety of the public by addressing threats to the distribution infrastructure. The legislation will not be effective unless it includes provisions for ongoing funding such as federal grants to support these efforts. This funding is intended to be in addition to, and independent of, existing federal funding of state pipeline safety programs*[12].

Addressing these findings will help establish a situation in which those responsible for excavation damage to pipelines will be required and motivated to modify behavior in a way that will reduce the frequency of such damage. As noted in the first key finding above, this represents the greatest single opportunity for distribution pipeline safety improvements.

Excess Flow Valves

Excess Flow Valves (EFV) are devices that can be installed in each service line and that may shut off gas flow if the line is severed downstream of the valve. These valves represent a measure that may mitigate the consequences of some incidents if they occur despite the preventive actions that may be taken to reduce the likelihood. PHMSA reported, in its May 2005 report to Congress, that EFVs would be considered as part of this program.[13] The basis for this was reported to be that their use would be similar to additional preventive and mitigative measures that operators of hazardous liquid and gas transmission pipelines are required to consider as part of the integrity management regulations applicable to those pipelines, such as emergency flow restricting devices for hazardous liquid pipelines or automatic/remote control valves for gas transmission.

All work/study groups considered the question of how EFVs could best be treated within distribution integrity management requirements. The Data Group considered surveys conducted by the National Regulatory Research Institute (NRRI) for the National Association of Regulatory Utility Commissioners (NARUC) and by PHMSA, studies performed by PHMSA concurrently with this program, and data that it collected from operators who have installed EFVs for many years to evaluate the extent of use and efficacy of the valves. The Excavation Damage Prevention Group considered the usefulness of EFVs in mitigating incidents caused by excavation damage. The Strategic Options Group and the Risk Control Practices Group considered means by which requirements addressing use of EFVs could be incorporated into any new distribution integrity management requirements.

In addition, PHMSA conducted a public meeting on EFVs on June 17, 2005. Members of work/study groups participated in that meeting, and the comments made at that meeting were considered in the work/study group deliberations.

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[12] Conforming changes to 49 CFR Part 198 also will be needed if this legislation is enacted.
[13] Ibid, p. 25

From its review of relevant data, the Data Group reached a key finding:

> *The preponderance of information supports the conclusion that, when properly specified and installed, EFVs function as designed*

This finding addresses concerns that have been raised that EFVs either would not function as intended to shut off the flow of gas in the event of the rupture of a service line or that they would actuate when not required, thus necessitating action by pipeline operators to restore gas service to customers with intact service lines. The available data now supports the reliability of EFVs.

The Strategic Options Group reached a key finding on how a requirement addressing the use of EFVs could be included in distribution integrity management requirements.

> *As part of its distribution integrity management plan, an operator should consider the mitigative value of excess flow valves (EFV)s. EFVs meeting performance criteria in 49 CFR 192.381 and installed per 192.383 may reduce the need for other mitigation options. It is not appropriate to mandate excess flow valves (EFV) as part of a high-level, flexible regulatory requirement. An EFV is one of many potential mitigation options. (One member, representing the public, did not subscribe to the group conclusion on this issue).*

The Strategic Options Group report (attached) provides additional discussion of how such a requirement might be formulated.

The International Association of Fire Chiefs (IAFC), on behalf of itself and other organizations representing fire fighters, submitted comments to PHMSA espousing a different conclusion. IAFC participated in the June 2005 public meeting on EFVs and was thereafter invited to participate in activities of the Risk Control Practices and Excavation Damage Prevention Groups to assure that its strong views on EFVs would be represented in this program. IAFC did not participate. Nevertheless, they were provided a draft copy of the Risk Control Practices Group report for review. Their written comments to PHMSA, provided following their review of that draft report, are included as Appendix D to this report.

Data Reporting

Our understanding of the state of distribution pipeline safety and the actions that could be taken to improve it are founded in the data concerning current and historical performance. This effort included significant review of available data. That review highlighted areas in which improvements in the data could improve understanding.

PHMSA changed the form used by operators to report incidents in early 2004. This action, among other changes, increased the number of threat categories to which incidents must be characterized to the eight noted above. This change particularly expanded the former category of "damage by outside forces" to separate out excavation damage, natural forces, and other outside force damage. This refinement makes the recent incident report data more useful in understanding the significance of the threats facing distribution pipeline systems.

Data regarding leaks is another performance metric that can be used to evaluate the efficacy of distribution pipeline safety efforts. Operators report leaks on annual reports that they are required to submit.[14] The annual report form requires that operators report "Total Leaks Eliminated/Repaired During Year," separated into whether they occurred on mains or services and broken down by the same eight threat categories used for incident reports. Operators must also report "Number of Known System Leaks at End of Year Scheduled for Repair" with no breakdown as to location or cause.

Reporting is inconsistent among operators, in part because of the focus on leaks eliminated/repaired. Not all leaks require repair. Many leaks are small, such as leaks from threaded fittings, and pose no hazard. Some operators may elect to repair small leaks, for example because of upgrades to a portion of their system. Others monitor such leaks. As a result, data reported by some operators includes only leaks that were repaired because they posed a potential hazard, while data from other operators includes many leaks eliminated for other reasons. Comparisons and analysis using this data must therefore be done with great caution, and it is difficult to reach firm conclusions. The difficulty of using available leak data has previously been identified by AGF.[15]

The Data Group concluded that changes in leak reporting would be appropriate.

> *Several data reporting changes were suggested, including reporting of hazardous leaks removed by material; this could provide data to support a leak-related national performance measure*

Performance Measures

It is important to measure performance in order to determine whether a regulatory change has the desired effect of improving pipeline safety. The suggested elements of a distribution integrity management regulation (see "Regulatory Needs" above) would require that operators measure their performance and use those measures to help determine whether changes to their integrity management programs are needed. At the national level, performance measures would also be useful to allow PHMSA to determine if changes are needed to regulation or oversight.

Operators of gas transmission lines are similarly required to measure their performance and use those measurements to assess the efficacy of their programs. Transmission pipeline operators are also required to submit to PHMSA four overall performance

[14] 49 CFR 191.17
[15] American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure," January 2005, page 6-1.

measures, to be used on a national level for monitoring the effectiveness of the integrity management regulation.[16]

The Data Group concluded that national reporting of a small set of performance measures would also be appropriate for distribution pipelines.

> *Approach to characterizing the National performance baseline is described in the report (Attached); reference was made to areas in which current information will not support definition of a baseline (e.g., maturity of IM practices)*

The Risk Control Practices Group and Excavation Damage Prevention Group considered what measures operators could use to monitor the effectiveness of their integrity management programs, and the group reports contain findings in this regard. The Strategic Options Group considered the findings and conclusions of the other groups in evaluating which performance measures would be most useful at a national level, and which operators should thus be required to report. The Strategic Options Group found that three categories of performance measures would be most useful:

> *Three categories of reported performance measures for use at the national level were identified*
> - *DOT Reportable incident statistics and normalized incident statistics (per mile or per service)*
> - *Excavation damages normalized by number of tickets*
> - *Refined measure related to leaks - no consensus on specifics*

Incidents are currently reported. The number of incidents, and their consequences, is the key national measure of distribution pipeline safety. For an individual operator, however, the measure is not as useful. There are approximately 125 incidents reported throughout the U.S. by distribution pipeline operators each year. Most pipeline operators report none. It would be extremely rare for an individual operator to experience two reportable incidents in a year. Still, the direct importance of the number of incidents as a measure of the national state of distribution pipeline safety makes it appropriate for reported incidents to be treated as an integrity management performance measure. No new reporting requirements would be needed to capture the number of incidents that occur. Reports currently submitted to PHMSA provide this information and can be used for integrity management purposes. As discussed below, however, this effort has found that some changes to the specific information included with each incident report would be useful.

As noted in its finding, the Strategic Options Group concluded that a measure related to leaks was needed, but that it should reflect different information from what is now reported on OPS annual reports. The group could not reach consensus on the specific changes to leak reporting which would be appropriate. The Data Group also considered

[16] 49 CFR 192.945(a).

the need for changes to leak reporting requirements. The Data Group concluded that annual reporting should be revised to limit reporting of leaks to those leaks eliminated that required immediate action (also called "hazardous" leaks) and that operators should also report the material of the pipe from which these leaks were eliminated.

A majority of the members of the Coordinating Group concluded that these changes would make leak information from the annual reports a useful integrity management performance measure. The representative of the American Gas Association did not agree with this conclusion as it relates to reporting pipe material. AGA supports the suggestion to nationally report leaks eliminated that require immediate action by cause in that this data provides the clearest and most meaningful national statistic. AGA concludes that it would be essential for operators to maintain pipe material data along with other diagnostic information on leaks in order to perform effective risk assessment and for the review and oversight of local regulators. However, AGA considers that it is not informative and, in fact, is potentially misleading to report leaks by pipe material at a national level, since a false correlation independent of the other causation factors could be derived.

In its discussion of this issue, the Executive Steering Group agreed that the underlying issue is the need for a proactive process to identify construction materials concerns that may affect distribution pipeline integrity. The Executive Steering Group concluded that this issue should be addressed outside the context of this Phase 1 effort.

Excavation damages, as defined in the Excavation Damage Prevention Group report, and the number of locate tickets received would be new reporting requirements. Such measures are important in light of the fact that excavation damage is the most significant cause of distribution pipeline incidents and that preventing damage is the most effective means of reducing such incidents. To minimize the added burden to operators to report this data, it would be most appropriate for it, too, to be incorporated into the PHMSA annual report.

4. Path Forward

This first phase of evaluating the application of integrity management principles to distribution pipelines involved fact gathering and analysis. Much work remains to be completed before regulations and supporting guidance, leading to effective implementation of integrity management, are in place. During the course of their investigations, the work/study groups reached conclusions regarding activities that will be needed in future phases. These conclusions are reported in the work/study group reports for the benefit of those who will be involved in future work, but are not separated out as distinct sections.

Based on findings from this report, PHMSA will decide on future activities. The Coordinating Group would expect that PHMSA will collaborate with the National Association of Pipeline Safety Representatives (NAPSR), the group representing the managers of state pipeline safety agencies, since most distribution pipelines are under state regulatory jurisdiction. No action plan now exists for future work. PHMSA, with NAPSR, will need to develop one. The participants involved in Phase 1 hope that the work/study group conclusions regarding needed future actions will assist PHMSA and NAPSR in developing that action plan.

As with findings in the previous section, the Coordinating Group concluded that it would be worthwhile to highlight in this summary report the key conclusions of the work/study groups regarding future actions to be accomplished. The work/study groups were again asked to identify the most important of the actions discussed in their reports. These are presented in the following sections, again organized around the major issues of concern. This summary of actions is intended to allow readers of this summary report to gain an overall view of the most important future actions. The complete lists of actions identified by the work/study groups for the path forward are presented in Appendix C.

Regulatory Needs

There is presently no requirement that operators of distribution pipelines implement integrity management principles. Participants in this phase 1 effort have assumed that new requirements would be developed in future phases, and have explicitly identified that need.

> *Develop a high-level, flexible rule requiring integrity management for distribution operators*

This action is consistent with the key finding of the Strategic Options Group that a high-level, flexible federal regulation, excluding no operators and supported by implementation guidance, is an essential element of implementing integrity management principles. Developing federal regulations for pipeline safety is uniquely a PHMSA responsibility. Existing law requires that states adopt requirements at least as stringent as those established by PHMSA to maintain their certification to exercise regulatory jurisdiction over pipeline safety. This requirement will assure that a federal rule, which provides for a consistent approach to distribution integrity management, is implemented by the states that have such jurisdiction.

Guidance

Adequate guidance will be critical to facilitating operator implementation of the flexible requirement for integrity management described in the Key Findings section above. Developing that guidance will thus need to be a key element of the future action plan. The Risk Control Practices Group considered the scope of guidance that will be needed.

> *Request GPTC to develop guidance to support implementation of integrity management requirements (see finding 4/5-8 in the Risk Control Practices report attached) and to address other areas in which existing guidance may require improvement to better assure the integrity of distribution pipelines (finding 4/5-9).*

The Strategic Options Group also identified the need for guidance as a key element of the path forward:

> *Develop guidance to support operator implementation of any resulting rule and decision support guidance for any EFV-related requirement*

Both groups recognized the development of guidance as a key element of the work that needs to be performed. The Strategic Options Group conclusion adds to the needs identified by the Risk Control Practices Group the specific element of guidance supporting a decision for implementing an EFV requirement.

Implementing integrity management will be particularly difficult for the smallest distribution operators, since they lack resources to devote to developing customized integrity management approaches. The issues faced by the smallest operators are likely to be similar, since their systems are likely to be smaller and simpler. The work/study groups concluded that it will be necessary to provide specific guidance that small operators can use. In particular, the Risk Control Practices Group concluded there is a need to:

> *Develop and implement an approach for preparing guidance for small operators*

Although the principal focus of this action is to develop guidance for the smallest operators, the Coordinating Group concludes that the guidance should be available to all. Any future regulatory requirements should apply equally to all operators, consistent with the Strategic Options Group finding that new requirements should exclude no operator. The Coordinating Group expects that guidance for the small operators will be structured around the relative simplicity of their systems. For example, the guidance may suggest specific actions if the system contains only one kind of pipeline material. Use of such guidance by any operator whose system, or sub-systems, meets the conditions inherent in the guidance (in this example, a single material) should be acceptable regardless of the operator’s size. The Coordinating Group expects that larger operators, with more available resources, may desire flexibility in developing their own plans rather than following any small operator guidance, but the option should still be available to them.

Preventing Excavation Damage

As noted in the key findings above, preventing excavation damage will necessarily involve affecting the behavior of persons not subject to pipeline safety regulation (i.e., excavators). Preventing excavation damage is thus an area in which significant actions are needed that go beyond the authority of pipeline safety regulators to implement. The Excavation Damage Prevention Group considers that the most effective means to induce states to implement the comprehensive damage prevention programs that are needed to reduce the incidence of pipeline damage would be federal legislation.

> *Propose Federal legislation, including appropriate funding mechanisms, to support state implementation of effective damage prevention programs that*

> *incorporates the nine essential elements (described in the Excavation Damage Prevention Group report). Encourage incorporation in next PHMSA reauthorization*

The Excavation Damage Prevention Group, working with PHMSA Counsel, has developed draft legislative language to accomplish this objective. That language is included in the Excavation Damage Prevention Group report.

Federal legislation, and implementation of comprehensive damage prevention programs by states in response to that legislation, will help reduce instances of damage to underground facilities, including pipelines. Assuring compliance with damage prevention requirements, though, will still require that the behavior of excavators be targeted. The Excavation Damage Prevention Group concludes that necessary change cannot be brought about without education.

> *Design and implement effective public education programs regarding excavation damage prevention - efforts to promote awareness and use of "811" should be included at core*

The reference to "811" within this action reflects the recent decision by the Federal Communications Commission to designate 811 as the national abbreviated dialing code to be used by state One Call notification systems for providing advanced notice of excavation activities to underground facility operators, in compliance with the Pipeline Safety Act of 2002.[17] Under the FCC rule, 811 must be used as an abbreviated dialing code for one-call centers by April 13, 2007. This change will undoubtedly be accompanied by education programs to inform the public of the new, abbreviated dialing arrangements. These education programs will provide an opportunity to further emphasize the importance of preventing damage to underground pipelines.

In addition, PHMSA published a rule on May 17, 2005[18], requiring that pipeline operators develop and implement improved public education programs. These programs also provide an opportunity to emphasize the importance of preventing damage to pipeline facilities.

Data Reporting

As discussed in the key findings section of this report, limitations in the available data made it difficult to draw conclusions regarding distribution pipeline integrity. Two of the work/study groups reached specific conclusions regarding additional information that, if included in PHMSA data reporting, would facilitate future analyses.

> *Consider revisions to incident data form (PHMSA 7100.1) and its instructions addressing the causes of incidents resulting from vehicles hitting gas facilities*

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[17] 70 FR 19321.
[18] 70 FR 28833.

An analysis of recent incident data conducted by Allegro Energy Consulting for PHMSA found that vehicles striking portions of pipeline systems (often meter sets) caused 11 percent of all distribution incidents over the five-year period analyzed.[19] Data are not available to understand these incidents or to help focus actions to prevent their occurrence. The Risk Control Practices Group finding is intended to assure that data is available for future analyses of this threat. The Coordinating Group concluded[20], based on input from the Data and Strategic Options Groups, that there is a need to:

Consider changes to data reporting

- *Require additional information for incidents when cause is excavation damage – identify useful information from review of the Damage Information Reporting Tool (DIRT) and state reporting requirements*
- *Expand incident report form to add information on the causes of incidents resulting from vehicles hitting gas facilities*
- *Report hazardous leaks eliminated by material in addition to cause; indicate presence of protection (e.g., coating, cathodic protection)*
- *Report hazardous leaks eliminated rather than all leaks eliminated/repaired during the year and the known system leaks at the end of the year scheduled for repair*
- *Add a check box (and appropriate criteria) on whether the regulations clearly require reporting or whether the report is submitted at the discretion of the operator*

These changes are all intended to address limitations in the currently-available data that hampered the ability to understand fully the issues related to distribution integrity management. Making these changes would facilitate future analysis of the effectiveness of regulatory changes in this area.

Performance Measures

The purpose of performance measures, as discussed in the key findings section above, would be to provide information that could be used to evaluate the effectiveness of new distribution integrity management requirements. The regulations would be demonstrated to be effective if the performance measures show improvement in the state of distribution integrity. All Work/study groups and the Coordinating group agree that tracking performance is needed.

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[19] Trench, Cheryl J., “Safety Incidents on Natural Gas Distribution Systems: Understanding the Hazards”, April 2005, page 23.

[20] As described above, the representative of AGA on the Coordinating Group did not agree that the change related to reporting leaks eliminated by material was needed, and the Executive Steering Group agreed that the underlying issue is the need for a proactive process to identify construction materials concerns that may affect distribution pipeline integrity, to be addressed outside the context of this work.

> *Track damage prevention metrics both for internal use in evaluating the effectiveness of an operator's program (by operators) and for evaluating progress at the national level.*

The Data Group found that to show improvement, it will be necessary to know the level of performance that was being obtained before any new requirements are implemented.

> *Once reportable Performance Measures are finalized, develop a national baseline from which trends in performance can be monitored, and a means of tracking trends from the baseline*

In addition, the Coordinating Group addressed the issue of how best to assure that valid conclusions are drawn from future analysis of reportable performance data. These data are complex and drawing valid conclusions from analysis may require insights only available through discussion involving a cross-section of knowledgeable regulators and operators. Therefore, the Coordinating Group concluded that it would be appropriate to:

> *Form a joint stakeholder group to conduct an annual data review, to resolve issues, and to produce a national performance measures report.*

Research and Development

A key finding of the Strategic Options Group (described above) was that continued research and development (R&D) is an element of the "best options" for implementing distribution integrity management. R&D can provide for improved methods of assessing the condition of distribution pipelines and for mitigating threats to distribution pipeline integrity.

The Excavation Damage Group identified one R&D project as a key path forward action. This action involves an issue for which PHMSA is already planning a pilot project. The group concludes that the pilot project will have value in enhancing protection of distribution pipelines from the principal threat to their integrity.

> *Conduct pilot project to research, develop and implement technologies to enhance the communication of accurate information between excavators and operators*

Scope

The Strategic Options Group also considered the appropriate scope of new regulations. In particular, the group considered the treatment of pipelines that are classified as transmission pipelines because they operate at stress levels greater than 20 percent of specified minimum yield strength (SMYS). These pipelines are currently subject to the integrity management requirements for transmission pipelines in 49 CFR Part 192, Subpart O. In promulgating Subpart O, however, PHMSA recognized that these pipelines are different than transmission pipelines operating at higher stresses, since these low-stress pipelines pose relatively lower risk.[21] Subpart O provided for alternative reassessment methods for these low-stress pipelines (operating below 30 percent SMYS) in recognition of their relatively low risk.[22]

Many low-stress transmission pipelines are operated by local distribution companies. Often these lines represent the only transmission pipelines for which the operators are responsible. Since these operators likely will be required to implement integrity management plans for their distribution pipelines, it might be more appropriate to allow them to treat their low-stress transmission pipeline under their distribution integrity management plans. In considering the appropriateness of such a change, the Strategic Options Group evaluated the existing research concerning the likely failure mode of pipeline operating below 30 percent SMYS to ascertain the accuracy of the commonly-stated belief that such pipeline tends to fail by leakage.

The group discovered that the record indicates that failure is expected to be by leakage when the failure results from corrosion. It is less clear that the likely failure mode would be leakage when the failure results from prior mechanical damage (e.g., from outside force). Additional technical work is needed to better define the threshold stress level at which the likely failure mode transitions from leakage to rupture to evaluate the appropriateness of treating low-stress transmission pipeline under distribution integrity management programs.

The Strategic Options Group thus reached a finding regarding appropriate consideration of low-stress transmission pipeline in any future rulemaking:

> *Consider whether low stress pipes currently defined as transmission should be treated as distribution for purposes of Integrity Management. Conduct additional research to define the threshold stress level at which pipe with latent mechanical damage is expected to fail by rupture.*

5. Conclusion

The Phase 1 investigations have demonstrated that the operation of distribution pipeline systems is currently safe. Incidents, including incidents involving fatality and injury, do occur. Their number is small. The number of incidents per 100,000 miles on distribution pipeline systems has been lower than the corresponding number for transmission pipelines for the last several years. The number of incidents involving fatality or injury per 100,000 miles has been similar to the number for gas transmission pipelines. Still, implementing integrity management principles, as has already been done for transmission pipelines, can result in an improvement in this already-good safety record.

The foundation for implementing integrity management principles for distribution pipelines is secure. Considerable information and many good practices are now available

[21] 68 FR 69797.
[22] 49 CFR 192.941.

that would be useful in this endeavor. Additional work is needed, however. New requirements and new guidance are both needed. Other changes, described in this report, would also help facilitate the effective implementation of integrity management for distribution pipelines.

The Phase 1 work described herein has resulted in findings and conclusions and suggestions for future action that will serve to support the effective implementation of integrity management for distribution pipelines.

As a separate, related effort, the Executive Steering Group prepared a statement on cost recovery for distribution integrity management to inform later actions of operators and rate regulators. That statement is included as Appendix E to this report.

Appendices

A. Participants

B. Complete list of Findings

C. Complete list of Path Forward Actions

D. Comments of International Association of Fire Chiefs

E. Statement on Distribution Integrity Management Cost Recovery

Appendix A

Participants

Executive Steering Group

Bender, Frank	Baltimore Gas & Electric
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Hatch-Miller, Jeff	Arizona Corporation Commission (NARUC)
Kelly, Linda	Connecticut Department of Public Utility Control (NARUC)
Kuprewicz, Rick	Accufacts, Inc. (Public)
Mason, Don	Ohio Public Utilities Commission (NARUC)
Miller, George	National Association of State Fire Marshals (Public)
Traweek, Lori	American Gas Association

Coordinating Group

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Israni, Mike	Pipeline & Hazardous Material Safety Administration
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Steele, Ed	Ohio Public Utilities Commission (NAPSR)

Strategic Options Group

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Gibson, Gary	City of Springfield
Kuprewicz, Rick	Accufacts, Inc. (Public)
Leonberger, Bob	Missouri Public Service Commission (NAPSR)
McDaniel, Mary	Railroad Commission of Texas (NARUC)
Nichols, Kris	Nicor Gas
Palkovich, Mary	CenterPoint Energy
Huston, Roger	Cycla Corporation

Risk Control Practices Group

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Gordon, Darrin	City of Stafford
Hansen, Bruce	Pipeline & Hazardous Material Safety Administration
Jolly, John	Philadelphia Gas Works
Miller, George	National Association of State Fire Marshals (Public)
Nicoletta, Gavin	New York State Public Service Commission (NARUC)
Reynolds, Lee	NiSource
Schmitz, Jerry	Southwest Gas
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Stursma, Don	Iowa Utilities Board (NAPSR)
Gawronski, John	Cycla Corporation

Excavation Damage Prevention Group

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Carrara, Bruno	New Mexico Public Regulation Commission (NAPSR)
Jones, Michael	Philadelphia Gas Works
Kipp, Bob	Common Ground Alliance (Public)
Lonn, Rick	AGL Resources, Inc.
McGrath, Mike	Minnesota Dept. of Public Safety – OPS (NARUC)
Megaw, Stu	Associated General Contractors of America (Public)
Paskett, Bruce	NW Natural
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Herb Wilhite	Cycla Corporation

Data Group

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Kent, Kevin	City of Mesa, Arizona
Lemoff, Ted	National Fire Protection Association (Public)
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Phillip Murdock	Atmos Energy
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Talukdar, Piyali	Volpe Center
Thompson, Michael (Chair)	Oregon Public Utility Commission (NAPSR)
Paul Wood	Cycla Corporation

Appendix B

Complete List of Findings

(Note that numbering is provided solely for ease of reference and is not intended to reflect relative priorities among the findings)

Strategic Options Group

1. The most useful option for implementing distribution integrity management requirements is a high-level, flexible federal regulation, in conjunction with implementation guidance, a nation-wide education program expected to be conducted as part of implementing 3-digit dialing for one-call programs, and continuing research and development
2. Model state legislation, guidance for mandatory adoption by states, and a prescriptive federal regulation are not considered useful options to address the question of distribution integrity management
3. Model state legislation may be useful for the narrower issue of improving excavation damage prevention through implementation of comprehensive damage prevention programs including active enforcement
4. A small number of elements are all that is needed to describe the basic structure of a high-level, flexible federal regulation addressing distribution integrity management. (These elements are presented graphically in Attachment B to the Strategic Options Group Report).
5. Implementation of the elements of a distribution integrity management regulation should be based on information that is reasonably knowable to an operator and on information that can be collected on a going-forward basis. Extensive historical research need not be required or expected.
6. It would not be appropriate to exclude any class or group of local distribution companies/agencies from distribution integrity management requirements
7. It would be inappropriate to require an operator to develop two separate integrity management programs solely to address pipe that is in the range of 20 to 30 percent SMYS if the failure mode of that pipe is similar to other distribution pipeline. Accordingly, it may be necessary to provide an option whereby pipeline at these stress levels, currently defined as transmission pipeline and subject to the provisions of 49 CFR Subpart O, can be treated by distribution pipeline operators under their distribution integrity management programs. Further work is needed to define the threshold stress level at which failures would be expected to occur by rupture from latent mechanical damage.
8. As part of its distribution integrity management plan, an operator should consider the mitigative value of excess flow valves (EFV)s. EFVs meeting performance criteria in 49 CFR 192.381 and installed per 192.383 may reduce the need for other mitigation options. It is not appropriate to mandate excess flow valves (EFV) as part of a high-level, flexible regulatory requirement. An EFV is one of many potential mitigation options. (One member did not subscribe to the group conclusion on this issue).
9. A separate treatment of EFVs, i.e., outside of integrity management requirements, may be more appropriate.
10. It would be appropriate for operators to be required to submit information periodically to PHMSA and states on a limited number of performance measures to enable the effectiveness of distribution integrity management requirements to be trended. Operators could benefit from more detailed performance measures to monitor and improve their own performance, which need not be submitted to regulators.

11. The most useful performance measures at the national level would be incidents (per mile or per service), number of excavation damages per "ticket", and a redefined measure or measures related to leaks. (The SOG could not reach consensus on a particular leak measure. Possibilities include hazardous leaks, corrosion leaks, and material leaks, each per mile or per service)
12. Performance measures regarding the type and amount of pipe in an operator's system and number of excavation damages would be less useful at a national level
13. Considering the wide diversity among distribution pipeline operators, it would be most appropriate to rely on guidelines for the general implementation of integrity management requirements and to look to technical standards only for specific details.
14. The principal benefit from implementing integrity management regulations is expected to be a reduction in the number of incidents and their consequences (i.e., deaths, injuries, and property damage)
15. Any changes resulting from distribution integrity management efforts that reduce the frequency of third-party damage events will result in significant benefit to gas distribution operators
16. It is likely that other benefits that can be considered other than avoided incident consequences will need to be identified.
17. The costs for implementing distribution integrity management requirements will likely include costs for developing written plans, performing risk analyses, and integrating information about pipeline condition. It is expected that these activities will be required of all operators subject to the requirements.
18. The costs associated with integrity management requirements will include any additional risk control practices that must be implemented and the effort to verify their effectiveness.
19. Estimating costs for implementing risk control practices requires knowledge of the practices that operators are likely to need to implement or modify. That information is not now available, because of the wide diversity of operators and the programs/activities they now employ. The American Gas Association and American Public Gas Association can help provide estimates for the costs that may be associated with risk control practices once the specific practices to be considered have been defined.
20. There would be value, particularly for small operators and state pipeline safety regulatory agencies, in an independent effort to collect, analyze, and disseminate information learned from operating experience throughout the industry. It is not clear at this time how such an effort might be funded.

Risk Control Practices Group

General Findings

1. The Pipeline and Hazardous Materials Safety Administration (PHMSA) plan for a "high level, risk-based, performance-oriented Federal regulation"[23] is supported by the following:
   - The elements necessary to implement a distribution integrity management program have been identified
   - Methods exist for operators to develop the elements
   - Operators may need additional guidance materials to aid in utilizing the existing methods, procedures and practices to complete their development of their distribution integrity management program
2. Since the entire distribution will be covered by the proposed distribution integrity management plan, there is no need to identify high consequence areas or identified sites.
3. There are no major areas of 49 CFR 192 that need to be changed to address distribution integrity management, with the exception of a high-level, risk-based, flexible performance regulation to require a written distribution integrity management plan by the operator, although some incidental revisions may be needed to avoid duplication or conflict. The requirement should be for a broad framework of risk-based actions to address those areas where the risk to public safety is the highest. There is a need for additional guidance materials to assist some operators in developing their integrity management programs.

Specific Findings (These findings are numbered in the Risk Control Practices Group report to correspond to group task numbers and report exhibits.)

1. A distribution integrity management program should consider the threats identified in the Pipeline and Hazardous Materials Safety Administration (PHMSA) Annual Distribution Report, PHMSA Form 7100.1-1 as "Cause of Leaks" in Part C:

1	Corrosion	5	Material or welds (Construction)
2	Natural Forces	6	Equipment
3	Excavation	7	Operations
4	Other Outside Force	8	Other

2. The distribution system characteristics must be identified.
3. The threats applicable to the system must be determined.
4. There is insufficient data regarding vehicle damage to gas facilities and other outside forces affecting gas facilities to develop a coherent understanding of the nature of the problem, and therefore, it is not possible to develop strategies to address this issue. It is an area where additional data needs to be developed.

[23] "Assuring the Integrity of Gas Distribution Pipeline Systems," Report to the Congress, May 2005, Submitted by Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, p. 3.

5. The threats applicable to the system must be prioritized using risk control principals where risk = likelihood * consequence.
6. Operators may need guidance on how to characterize their system, identify the threats and to prioritize the threats.
7. Since the entire distribution will be covered by the proposed distribution integrity management plan, there is no need to identify high consequence areas or identified sites.
8. Risk control practices exist that can be used to address the integrity of distribution systems.
9. One risk control practice is an effective leak management program, the essentials elements of which are:
   1) ***L*****ocate** the leak,
   2) ***E*****valuate** its severity,
   3) ***A*****ct** appropriately to mitigate the leak,
   4) ***K*****eep** records, and
   5) ***S*****elf-assess** to determine if additional actions are necessary to keep the system safe.
10. Operators may need guidance on the application of available risk control practices to their systems.
11. Operators should consider the use of excess flow valves (EFVs) as a risk control practice to be used where appropriate.
12. Current design, construction, installation and initial testing regulations should be effective in providing for integrity of the distribution facilities that are being installed today,
13. Current operating and maintenance sections (including Subpart I of 49 CFR 192) should be effective in providing the elements necessary to maintain the integrity on distribution lines,
14. Part 192, specifically §192.605 and 192.613, does not convey the concept of a risk-based distribution integrity management process that includes gathering system knowledge (surveillance), identifying trends, analyzing and prioritizing integrity threats and controlling the integrity related risks by prevention, detection and mitigation activities.
15. Part 192 needs a regulation that specifically requires a distribution integrity management program that includes the following elements:
   1 The operator develop a written program plan that describes how it manages the integrity of its distribution system and focusing on how it will satisfy the requirements below. As operators develop formal integrity management programs, they will be guided both by federal and state requirements, as well as by their own analysis of their systems.
   2 The operator identify threats applicable to its system.
   3 The operator characterize the relative significance of applicable threats to its piping system.

   4. The operator identify and implement appropriate risk control practices (or modify current risk control practices) to prevent, and mitigate the risk from applicable threats consistent with the significance of these threats.
   5. The operator develop and monitor performance measures to allow it to evaluate the effectiveness of programs implemented.
   6. The operator periodically evaluate the effectiveness of its program and make adjustments dictated by its evaluation.
   7. The operator periodically report to the jurisdictional regulatory authority a select set of performance measures.

16. Part 192 has some areas where minor changes would result in some improvements as relates to distribution integrity management issues (see Task 4 and Task 5).
17. Some States have requirements or programs related to distribution integrity management that exceed those of Part 192 and cover the following areas:
    - a Pipe Replacement - Mains
    - b Pipe Replacement – Services and Appurtenances
    - c Leak Management including leak response time and backlogs of scheduled leak repairs
    - d Damage Prevention
    - e Corrosion Control
18. State requirements or programs exceeding Part 192 are often tailored for the local conditions 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 should be considered by operators in developing their individualized risk control program.
19. The ANSI Z380 Gas Piping Technology Committee (GPTC) should develop guidance material in the ANSI Z380.1, American National Standard for Gas Transmission and Distribution Piping Systems (GPTC Guide) to assist operators in determining which practices and methods are most appropriate for use by operators in prioritizing threats to their systems, which risk control practices are most appropriate for use by operators in addressing threats to their systems and which performance measures are most appropriate for use by operators in evaluating their risk control program.
20. The Gas Piping Technology Committee (GPTC) should consider additional guidance in specific code areas identified in the Risk Control Practices Group report (see Task 4 and Task 5).
21. The American Society for Testing and Materials (ASTM) should consider the need to take action to enhance performance test protocols (for components, burst tests, etc.) for plastic fittings, to incorporate protocols for the evaluation of elastomer related issues (gasket & O rings) and to add requirements for permanent marking of pipe and appurtenances so that materials can be redressed in a proactive manner should indications of problems be identified.
22. Operators may need guidance materials to comply with a high-level, risk-based, flexible federal rule. Small operators may need more extensive guidance for compliance.

23. On-going research and development activities are important to develop new practices, procedures, techniques and equipment which may positively impact distribution integrity management.
24. National performance measures of distribution integrity management should include:
    1. Incident data contained in the Form PHMSA 7100.1.
    2. The status of the operator in complying with the required elements of the program in accordance with deadlines established by the regulation.
    3. The amount and ratio of pipe that is not considered "state of the art," i.e., pipe of a type which operators today would not normally install today (e.g., cast iron, unprotected steel and polyvinyl chloride (PVC)).
25. Operator-specific performance measures are unique and must match the specific risk control practices of its distribution integrity program as they are designed to address the threats to that system.
26. There is a lack on consensus as to whether measuring leakage, at a national level, is an appropriate measure of distribution integrity management.
27. The review of the operator's written distribution integrity management program should be at intervals not exceeding 15 months, but at least once each calendar year (the same interval currently required for review and update of its Operations and Maintenance (O&M) Plan (49 CFR 192.605)).
28. The operator should complete an evaluation of the effectiveness of its distribution integrity management program periodically. The period for the evaluation of program effectiveness should be specific in the plan and should be as frequent as needed to assure distribution system integrity.

Excavation Damage Prevention Group

1. Excavation damage poses by far the most significant threat to the safety and integrity of the natural gas distribution pipeline system. Therefore, excavation damage prevention presents the greatest opportunity for gas distribution system safety improvements.
2. Distribution pipeline safety and excavation damage prevention are intrinsically linked. Any effort to improve distribution pipeline safety is meaningless if it does not seriously address the threat of excavation damage prevention.
3. Although distribution pipeline operators are required to have damage prevention programs under 49 CFR Part 192, preventing excavation damage to pipelines is not completely under the control of operators.
4. Many states do not have comprehensive damage prevention programs including effective enforcement authority in spite of repeated attempts to pass effective damage prevention legislation.
5. Industry, regulators, excavators, CGA and One-Call Centers throughout the nation have made significant progress in reducing gas damages during the period from 2000 to 2004. Over this period, national gas distribution damages due to excavation were reduced from 132,478 to 108,577. This reduction of over 18 percent was due

principally to efforts by all parties in the areas or training, education and Operator Qualification to highlight a few.

6. Separating that reduction in excavation damages from 2000 to 2004 into states identified with comprehensive damage prevention programs (including effective enforcement by the state agency involved in pipeline safety) and those without, the reduction in damages for those with identified comprehensive programs is a reduction of 22.6 percent vs. a reduction in the other states of 17.5 percent.
7. Evaluating those excavation damages on a normalized basis of damages per 1000 tickets, the identified comprehensive damage prevention states had over a 20 percent lower damage rate in 2000 and a 26 percent lower damage rate in 2004 than the remaining states.

Damages/1000 Tickets	**2000**	**2004**
Other States	6.27	4.91
Comprehensive States	4.98	3.64
Percent Reduction	20.6%	25.9%

8. Review of each individual state's data for the five identified with comprehensive damage prevention programs (Connecticut, Georgia, Massachusetts, Minnesota, and Virginia) indicates a significant reduction in damages (30 percent or more) in the years immediately following the implementation of enforcement by the pipeline safety groups in each case.
9. Analysis of five individual states with comprehensive damage prevention programs that include effective enforcement by the state agencies with responsibility for pipeline safety (Connecticut, Georgia, Massachusetts, Minnesota, and Virginia) shows a material improvement in gas distribution excavation damages per 1000 tickets compared to individual states that do not have effective enforcement programs. For example, states with mature damage prevention programs that include enforcement, such as Virginia and Minnesota, have normalized excavation damage rates that are less than half the rates of states without effective enforcement programs.
10. Federal Legislation is needed to support the development and implementation of damage prevention programs that include effective enforcement as a part of the state's pipeline safety program. This is consistent with the objectives of the state pipeline safety programs which are to ensure the safety of the public by addressing threats to the distribution infrastructure. The legislation will not be effective unless it includes provisions for ongoing funding such as federal grants to support these efforts. This funding is intended to be in addition to, and independent of, existing federal funding of state pipeline safety programs.
11. A comprehensive damage prevention program requires nine important elements be present and functional for the program to be effective. These elements are discussed in detail later in the report.
12. Incentives (positive and negative) should be provided to operators, excavators, and locators to ensure compliance with the damage prevention program requirements.

13. Operators should review and implement CGA Best Practices and other industry practices as appropriate to help reduce damages to their facilities. Similarly, other affected stakeholders should review and implement applicable CGA Best Practices.
14. Damage metrics should be provided to the PHMSA by operators as a measure of natural gas distribution pipeline safety. Reportable metrics should include total damages, as defined herein, and normalized damages (damage ratio), defined as damages per 1000 tickets. This may require the revision of 49 CFR Part 191.
15. Operators should track additional damage prevention program metrics for internal use in evaluating the effectiveness of the operator's program.
16. Excess Flow Valves (EFV) are one tool that should be considered by operators to address the consequences associated with excavation damages.
17. All stakeholders must participate in the excavation damage prevention process.

Data Group

1. *<u>Which threats have greatest impact on distribution system safety?</u>*

   Threats having the greatest impact on distribution system safety are characterized below, with the source of the conclusion in parenthesis:
   - The dominant cause of distribution pipeline incidents (reportable) is "excavation damage", while the second and third leading causes are "other outside force" and "natural force", respectively (Allegro)
   - The dominant cause of distribution pipeline leaks removed is corrosion for both mains and services (Data Group)
     - "Excavation damage" is nearly as significant as "corrosion damage" for services (Data Group)
     - The second and third leading causes for both mains and services are "excavation damage" and "material/welds", respectively (Data Group)
   - The percentage of incidents caused by corrosion is approximately 4%, indicating that corrosion is currently managed to prevent it from becoming one of the major contributors to reportable incidents (Data Group)

2. *<u>Do data show whether threats are of increasing or decreasing concern, thereby supporting any conclusions on the effectiveness of existing integrity management programs?</u>*

   The following trends have been identified, with the source of the conclusion in parenthesis:
   - A decreasing trend in the rate of reportable distribution incidents resulting in fatalities and injuries exists for the preceding 13-year study period (AGF)
   - No statistically significant trend was determined for total reportable distribution incidents for the 13 year study period (AGF)
   - There is a downward trend for reportable incidents resulting in fatalities or injuries caused by outside force damage (AGF)

- There appears to be a slight downward trend in corrosion-caused leaks removed, and there appears to be a decreasing trend in leaks removed caused by third party damage - statistical analysis was not performed (Data Group)
- While anecdotal evidence indicates there should be a downward trend in the mileage of certain materials that are more likely to leak, data from the Annual Reports in this area are too inaccurate to support this finding (Data Group)

3. *How might the current performance baseline be characterized?*

- The national performance baseline for distribution pipeline system may be characterized using the following three factors:
  - DOT reportable incident statistics
  - Data on leaks removed
  - Information on system physical characteristics (e.g., miles of materials with an increased leakage potential such as unprotected ferrous materials or cast iron)
- So few incidents occur that incidents are not a meaningful baseline performance measure for operators or for individual states - most operators and many states experience zero incidents in a typical year
- Because of year-to-year fluctuations in the available data, the baseline related to incidents and leaks removed should be established based on an average of data over a three or five year period
- The current baseline related to the maturity of distribution IM practices cannot be determined based on current reporting requirements,
- Final determination of the best national baseline performance parameters should await identification of any changes to reporting requirements.

4. *Do data exist to support either focusing of new requirements on certain industry segments (e.g., master meters, propane operators or small operators) or excluding segments from new requirements?*

Based on analysis of the leakage data, we can conclude that there is *no clear basis* for excluding operators of any size from additional requirements designed to improve the integrity of distribution pipeline systems. Since no data exist for master meter and propane operators, no analysis was possible.

5. *Do data show any significant differences among states that may impact the findings from this Program?*

As a result of the very small number of incidents (often zero) in an individual state, differences among states in incident rates are not statistically significant. Therefore, conclusions are not possible from these data. Differences in “leaks removed” normalized to miles of main or number of services correlate well with the fraction of unprotected steel pipe in a state. This correlation, combined with large differences in miles of unprotected steel pipe, masks any differences that may exist due to the relative effectiveness of state programs. Hence, neither data on incidents nor on leaks removed shed light on the effectiveness of individual state programs.

The Excavation Damage Prevention Group has collected data on damages to distribution pipelines and on tickets issued per state. Conclusions based on analysis of these data are presented in their report.

6. *What changes to data reporting requirements might be valuable?*

Potentially useful changes to data collection requirements being considered include:

- Careful review DIRT and state reporting forms should be undertaken to determine whether additional information should be added when incident or leak cause is excavation damage.
- Annual Reports should be revised to require the reporting of only "leaks eliminated that required immediate action" (also termed "hazardous leaks"); the material of the pipe from which these leaks were eliminated should also be reported.
- There would be considerable value derived from formation of a joint stakeholder group to conduct an annual review of safety performance metrics data, to resolve issues, and to produce a national performance metrics report.
- Improvements in incident data collection requirements could contribute to better decisions on whether to install EFVs.

7. *What do we currently know about the performance and cost effectiveness of Excess Flow Valves (EFVs)?*

- Over 6.3 million EFVs have been installed in the USA,
- Analysis of information from surveys completed to date indicates that, if correctly specified and installed, EFVs function as designed,
- EFVs will not function in all applications - up to 60% of new services in Connecticut, a state that supports use of EFVs, will not support EFV use
- Different operators have reached different conclusions on whether the overall cost of installing EFVs on new and replacement services is favorable or unfavorable relative to that of complying with current notification requirements; operator conclusions seem to reflect their assumptions (e.g., whether or not they include litigation risk, how they treat cost recovery, the probability of an incident actually occurring)

8. *Would gathering of additional data on EFVs contribute to clarifying their benefits or costs?*

There is limited value associated with carrying out an expansive forward-looking EFV data collection effort. The Data Group concludes that the following represents a more effective course of action:

- AGA moving forward with its planned effort to promote exchange of factual performance and reliability information among its membership,

- APGA continuing to communicate real world experience with EFVs among its members,
- PHMSA, APGA and AGA developing EFV feasibility criteria, considering factors such as the following: line pressure, expected future changes in line pressure, the presence of liquids in the line, the presence of solid particles in the line, environmental conditions that could reduce EFV functionality, and the length of line from main to meter.

Appendix C

Complete List of Path Forward Actions

(Note that numbering is provided solely for ease of reference and is not intended to reflect relative priorities among the actions)

Strategic Options Group

1. Develop high-level, flexible rule requiring integrity management for distribution operators, excluding no operators
    a. Incorporate requirement to submit performance measures
    b. Incorporate requirement for additional internal performance measures (drawn from RCP and EDPG reports)
2. Develop guidance to support operator implementation of any resulting rule and to support decisions on any EFV requirement
3. Incorporate gas pipeline damage control message into 811 education programs
4. Consider whether low stress pipes currently defined as transmission should be treated as distribution for purposes of Integrity Management
    a. Conduct additional research to define the threshold stress level at which pipe with latent mechanical damage is expected to fail by rupture
5. As practices are defined by which operators could implement provisions of a new regulation, gather data on the costs on implementing these practices (from AGA/APGA)
6. Evaluate the value of an effort to collect, analyze and disseminate information on lessons from operating experience; determine how best to pursue such an effort if it appears to have value
7. Identify and conduct R&D aimed at developing new tools for investigating distribution system integrity or addressing mitigating factors that can improve integrity
8. Align future practices for data gathering to collect info relevant to IM plan that becomes available during the course of future work (by operators)
9. Revise annual reporting of leak information
10. Augment or reconstitute GPTC to add necessary expertise (e.g., representation of small operators), if GPTC is to develop guidance in this area

Risk Control Practices Group

Actions related to regulation:

1. A high level, risk-based, performance oriented Federal regulation including the following 7 elements is needed to address distribution integrity management:
    a. The operator develop a written program plan that describes how it manages the integrity of its distribution system and focusing on how it will satisfy the requirements below. As operators develop formal integrity management programs, they will be guided both by federal and state requirements, as well as by their own analysis of their systems.
    b. The operator identify threats applicable to its system.
    c. The operator characterize the relative significance of applicable threats to its piping system.

   d. The operator identify and implement appropriate risk control practices (or modify current risk control practices) to prevent, and mitigate the risk from applicable threats consistent with the significance of these threats.
   e. The operator develop and monitor performance measures to allow it to evaluate the effectiveness of programs implemented.
   f. The operator periodically evaluate the effectiveness of its program and make adjustments dictated by its evaluation.
   g. The operator periodically report to the jurisdictional regulatory authority a select set of performance measures.
2. The regulation need not address high consequence areas or identified sites as the entire distribution system will be included.
3. The regulation should address the elements of an effective leak control program.
4. The regulation need not address the details of elements b, c and d as these practices and techniques exist in the existing literature, except perhaps to address the issue of EFVs being considered as a risk control practice that should be considered by the operator.
5. The categories of threats to be considered should include the eight threats identified in the Pipeline and Hazardous Materials Safety Administration (PHMSA) Annual Distribution Report, PHMSA Form 7100.1-1 as "Cause of Leaks" in Part C:

Corrosion	Material or welds (construction0
Natural Forces	Equipment
Excavation	Operations
Other outside force	Other

6. Operator-specific performance measures in Element f above are unique and must match the specific risk control practices of its distribution integrity program as they are designed to address the threats to that system. The national performance measures in element g should include:
   a. Incident data contained in the Form PHMSA 7100.1.
   b. The status of the operator in complying with the required elements of the program in accordance with deadlines established by the regulation.
   c. The amount and ratio of pipe that is not considered "state of the art," i.e., pipe of a type which operators today would not normally install today (e.g., cast iron, unprotected steel and polyvinyl chloride (PVC)).
7. The review of the operator's written distribution integrity management program should be at intervals not exceeding 15 months, but at least once each calendar year (the same interval currently required for review and update of its Operations and Maintenance (O&M) Plan (49 CFR 192.605)).
8. The operator should complete an evaluation of the effectiveness of its distribution integrity management program periodically. The period for the evaluation of program effectiveness should be specific in the plan and should be as frequent as needed to assure distribution system integrity.
9. State requirements or programs exceeding Part 192 (such as pipe replacement programs and leak management programs) are often tailored for the local conditions 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 should be considered by operators in developing their individualized risk control program.

10. There are no major areas of 49 CFR 192 that need to be changed to address distribution integrity management, with the exception of a high-level, risk-based, flexible performance regulation to require a written distribution integrity management plan by the operator, although some incidental revisions may be needed to avoid duplication or conflict. There is a need for additional guidance materials to assist some operators in developing their integrity management programs.
11. Part 192 has some areas where minor changes would result in some improvements as relates to distribution integrity management issues (see Task 4 and Task 5 in report in Attachment 2).

Other actions:

1. Consider revisions to incident data form (PHMSA 7100.1) on the causes of incidents resulting from vehicles hitting gas facilities
2. PHMSA to continue its R&D Program to address integrity management issues
3. Request GPTC to develop guidance in accordance with findings 4/5-8 and 4/5-9
4. Develop and implement an approach for preparing guidance for small operators (possibly involving an expanded GPTC working group)
5. Consider whether additional guidance should be prepared by GPTC to expand on practices associated with elements of the "LEAKS" leak management program
6. Petition ASTM to expand performance test standards for plastic fittings
7. Identify how guidance material should be developed on choices for carrying out risk analyses to support implementation of findings from the DIMP report, consider data needs to support such modeling

Excavation Damage Prevention Group

1. Propose Federal legislation, including appropriate funding mechanisms, to support state implementation of effective damage prevention programs that incorporate the nine essential elements
    a. Encourage incorporation in next PHMSA reauthorization
2. Further consider choices for and means of providing incentives, both positive and negative, to stakeholders to assure compliance with program requirements
3. Review and implement CGA best practices and other relevant industry practices (by operators and other stakeholders)
4. Track damage prevention metrics for national reporting and for internal use in evaluating the effectiveness of an operator's program (by operators)
5. Conduct pilot project to research, develop and implement technologies to enhance the communication of accurate information between excavators and operators (under consideration by PHMSA)
6. Consider including elements of an effective damage prevention program in a rule

7. Design and implement effective public education programs. Efforts to promote awareness and use of "811" should be included at core

Data Group

1. Once reportable Performance Measures are finalized, develop a baseline from which trends in performance can be monitored and a means of tracking trends from the baseline
2. Implement an active communication program on EFV effectiveness (AGA to promote exchange of factual information among members; APGA to communicate real-world experience among its members)
3. Develop EFV feasibility criteria
4. Consider changes to data reporting
    a. Additional info when cause is excavation damage – from review of the Damage Information Reporting Tool (DIRT) and state reporting requirements
    b. Expand incident data form to add information on the causes of incidents resulting from autos hitting meter sets
    c. Report leaks by material in addition to cause; indicate presence of protection (e.g., coating, CP)
    d. Report hazardous leaks as subset of all leaks eliminated
    e. Check box indicating whether incident is being reported at discretion of operator (with appropriate criteria)
5. Evaluate year-to-year trends in hazardous leaks removed associated with states in which innovative or aggressive programs are in place to minimize leaks in pipes constructed from older materials such as cast iron or dated plastic

Appendix D

International Association of Fire Chiefs Letter on Excess Flow Valves

Appendix D – International Association of Fire Chiefs Letter on Excess Flow Valves

The International Association of Fire Chiefs (IAFC) participated in the June 2005 public meeting on EFVs and was thereafter invited to participate in activities of the Risk Control Practices and Excavation Damage Prevention Groups to assure that its strong views on EFVs would be represented in this program. IAFC did not participate. Nevertheless, they were provided a draft copy of the Risk Control Practices Group report for review. Their written comments to PHMSA, provided following their review of that draft report, are reproduced in this Appendix.

The IAFC did not review draft reports of other work/study groups. A number of their comments regarding deficiencies are addressed in those reports.

Ms. Stacey Gerard
Acting Assistant Administrator\Chief Safety Officer
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
400 Seventh Street, S.W., Suite 8410
Washington, D.C. 20590-0001

Dear Ms. Gerard:

I have read the draft document entitled, *Report of the Risk Control Practices Work Group*, and am pleased to comment on specific aspects of the report, especially as it pertains to the use of Excess Flow Valves (EFVs). My comments reflect the views of the International Association of Fire Chiefs (IAFC) and are supported by other organizations I represented at the public meeting held on June 17, 2005 regarding the EFV issues. Those other organizations are the International Association of Fire Fighters, the National Volunteer Fire Council, and the Congressional Fire Services Institute. The IAFC and the other fire service organizations represent our nation's first responders, who are most at risk from natural gas leaks. In any risk assessment, the greatest attention should be given to those who are the most at risk.

After review of the draft, *Report of the Risk Control Practices Work Group,* the above mentioned organizations would like to state for the record that our position has not changed. Our position remains that the universal use of EFVs should be a requirement rather than an option. We acknowledge that the Department of Transportation (DOT)'s Pipeline and Hazardous Materials Safety Administration (PHMSA) is moving in a forward direction on the issue of EFVs. However, we continue to request that PHMSA begin the rulemaking process to mandate the usage of EFVs.

The remainder of this correspondence is our assessment of those parts of the *Report of the Risk Control Practices Work Group* that are most relevant to our concerns.

We agree that gas distribution operators should implement integrity management programs that identify and assess the specific risks their systems pose to public safety and that they implement measures to minimize the identified risks. Some risk control practices/procedures now exist that can be used to address the many aspects of distribution system integrity. However, we believe that the draft report also should address the following issues:

1. The report does not adequately address excavation damage issues even though this type of damage to distribution systems is the major cause of incidents, deaths, and injuries. It also is a major reason to install EFVs.

2. Available data regarding vehicle damage to gas facilities and other outside forces affecting gas facilities is insufficient for developing a comprehensive understanding of the nature of the problem. Therefore, it is impossible to develop strategies to address this issue.

3. Guidance has yet to be developed for operators on the application of available risk control practices to their systems. Most operators will need guidance materials to comply with a high-level, risk-based, flexible federal rule. Small operators and most municipalities, if they ever are to perform such analyses, will need extensive guidance for compliance.

4. Each operator must have considerable knowledge of its distribution system for there to be a reasonable understanding of the gas system and the threats it poses to public safety. An operator must have knowledge of its natural gas distribution system including: location, material composition, piping sizes, joining methods, construction methods, date of installation, soil conditions (where appropriate), operating and design pressures, failure history, operating experience performance data, system condition, and any other characteristics noted by the operator as important to understanding its system.

We believe that the PHMSA must address strategies for reducing excavation damages and vehicle and other outside forces damages before trying to implement an integrity management program. As first responders, our organizations would not consider supporting an integrity management proposal before reasonable assessments have been made to better understand the excavation damage and outside force damage issues and before strategies have been developed to reduce these causes and their effects.

Further, because gas systems have been combined over the years through purchases and without the transfer of adequate records on the physical characteristics and operating histories of those systems, much of the information necessary to perform meaningful risk assessments is not available. Such deficiencies have been the reason that the industry frequently mismarks their networks because accurate maps of the system are not available. Mismarking leads to a majority of the third-party accidents that occur on gas distribution networks.

Many operators of small gas systems now are incapable of operating their gas systems in compliance with existing federal requirements. This deficiency demonstrates a need for the PHMSA to establish knowledge, education, and experience qualifications for managers and operators as prerequisites for owning and operating gas distribution systems. Under the current system, a person with no previous experience can legally be a gas distribution system operator. Due to the economic and technical challenges of municipal and small gas operators, only a few of the hundreds of gas operators and gas master meter system operators will be qualified to participate in integrity management programs. Many gas operators do not employ nor have available personnel capable of performing risk assessments or directing an integrity management program. It is troubling that this proposal does not address what action such gas operators must take with respect to installing EFVs.

Over the past 100 years, the gas industry has not developed and used a means to rapidly stop the flow of gas from major service line ruptures. Since the development of the EFV over 35 years ago, the gas industry has failed universally to install EFVs in service lines to rapidly stop the flow of gas from major ruptures. Since the DOT promulgated a rule six years ago that requires customer notification or EFV installation, the gas industry has not universally adopted the installation of any device such as an EFV on service lines to stop the flow of gas rapidly from major ruptures.

We do not believe that gas operators should be permitted to determine whether to employ specific safety devices, particularly when the lives of our first responders and the American public are on the line. Incorporating the decision on EFV installation in new or renewed gas services into integrity management only allows some gas operators who have long fought against added federal regulation to further deny protection essential to the safety of emergency response personnel and the public. We are concerned that few, if any, of those operators now opposed to the installation of EFVs will change their practice and begin installing EFVs under the proposed PHMSA integrity management rule.

Risk-based assessments should be used to identify integrity threats and to indicate the appropriate corrective action required in cases where the basic issue may not be the same for all systems. However, regulation-based control should be used for threats where risk control practices need to be uniform. We recognize that as a consequence of the DOT's customer notification regulation promulgated in 1999 more gas operators than ever before are now installing EFVs. We believe that such positive action needs to be required of all gas operators.

We believe that the need to rapidly stop the flow of gas from major ruptures of service lines is universal for all gas systems. We also believe that the installation of an EFV on all new and renewed gas services that have operating characteristics compatible with off-the-shelf EFVs is a universal corrective action requiring no further assessment. EFV use should be a requirement, not an option.

As a reminder to you about our position concerning the need for the PHMSA to promptly require use of EFVs, I am attaching a copy of the comments I made at your June 17, 2005, public meeting on EFVs. In closing, I reiterate that the views of first responders, such as fire organizations, should be given the greatest attention with respect to how the PHMSA deals with all issues relating to the installation of EFVs.

In closing, it is critical that these comments be included somewhere in the *Report of the Risk Control Practices Work Group*. Let me again thank you for allowing the IAFC and America's major fire service organizations to have a seat in the distribution integrity management process and for allowing the views of the nation's first responders to be heard. While we acknowledge that progress is being made with respect to EFVs under your leadership, we continue to urge you to enter into a rulemaking process mandating the prospective use of EFVs as soon as possible. The health and safety of the citizens and firefighters in the United States will be best served by this action.

Sincerely,

ORIGINAL SIGNED BY

Stephen D. Halford, Fire Chief

Enclosure

cc: The Honorable Norman Y. Mineta, Secretary of Transportation
The Honorable Curt Weldon, U.S. House of Representatives

Appendix E

Statement on Distribution Integrity Management Cost Recovery

Statement on Distribution Integrity Management Cost Recovery

I. PURPOSE

Integrity management plans for natural gas companies that operate distribution systems are being developed jointly by the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) and a taskforce composed of state regulators, industry and public stakeholders. Beginning in January 2006, PHMSA and its partners will develop appropriate requirements and state regulators will begin to prepare guidance and standards for local distribution companies. This guidance will include how the costs of related compliance programs will be recovered. This statement provides background on cost recovery related to distribution integrity management programs (DIMP), including basic recovery principles as well as descriptions of possible rate mechanisms.

II. BACKGROUND

PHMSA Report to Congress

In May 2005, PHMSA issued, "A Report to Congress: Assuring the Integrity of Gas Distribution Pipeline Systems." The report stated that while integrity management requirements for gas transmission pipelines are focused on physical inspections of the condition of those pipelines in areas where an accident could result in high consequences, gas distribution pipelines systems are very different from transmission pipelines and require an alternate means of assuring their integrity. The report went on to state that flexibility in creating standards was imperative, due to the wide variations in gas distribution pipeline systems. A combination of high-level performance standards with broadly accepted guidelines that would be implemented by state-specific requirements was deemed to be the best approach. Likewise, the report recognized potential financial burdens and the need for cost beneficial processes as areas of concern to operators.

NARUC Resolution

Once DIMP plans are established, the next step is to determine the most effective method of cost recovery. The National Association of Regulatory Utility Commissioners (NARUC) considered the issue of assuring the integrity of distribution pipeline systems at its winter meeting in February of 2005. NARUC adopted a resolution at that meeting supporting the joint efforts of PHMSA, gas distribution pipeline operators, and other stakeholders to develop an approach to better assure distribution pipeline integrity. The NARUC Resolution on

Distribution Integrity Management encouraged the development of risk-based, technically sound and cost-effective measures that balance continued safe operation, reliable service, and the implications of any increased financial demands on the customer.

Precedent of NARUC Model State Protocols for Critical Infrastructure Protection Cost Recovery

The NARUC Ad Hoc Committee on Critical Infrastructure considered the issue of protecting the critical infrastructure of America's natural gas and electric utilities. Much of the nation's critical infrastructure, i.e., natural gas distribution, electric distribution, and telephone systems, is subject to state regulation. In July of 2004, the committee issued a report the objective of which was to provide state regulators with information about the variety of workable cost recovery protocols for critical infrastructure protection that exist for energy utilities. Because most regulators did not feel the need to reinvent the wheel in order to design effective cost recovery mechanisms, the report noted that the existing inventory of cost recovery mechanisms was sufficient for critical infrastructure protection costs. Examples of these techniques included base rate cases, deferral accounts, and tracking mechanisms.

Pipeline and Distribution Rate Design Differences

The differences in rate design techniques available to the operators of gas distribution pipeline systems and gas transmission pipeline companies are important to note. Like transmission pipelines, distribution pipeline rates are set so that a utility has the opportunity to earn as a profit an amount of money equal to a percentage of the amount of money invested in the facilities used and useful in providing service to the utility's customers. This profit, along with operating and maintenance expenses, and for distribution companies, gas commodity costs, constitutes a pipeline's cost of service. Most distribution utilities' cost to provide service are recovered through volumetric rates, while most of FERC-regulated transmission pipelines' charges are recovered through demand based rates that use cost of service as a ceiling price but are frequently negotiated between the parties.

Volumetric rates are those that attempt to recover a utility's total revenue requirement, also known as its cost of service, by allocating equal portions of those costs to each volume of gas that the utility forecasts that it will deliver. In some years, the utility delivers more gas than it forecast, and in that year the utility "over-recovers" its cost of service. In other years, the utility "under-recovers" because it delivers less gas than its forecasts predicted. Over time, the utility expects to recover very close to its actual cost of service.

Demand rates are those that attempt to recover a pipeline's total revenue requirement by allocating costs to each customer in proportion to how much usage or "demand" each customer places on the pipeline's services. Regardless of the amount of gas that each customer has delivered through a pipeline's transmission system, the pipeline receives a constant demand charge from that customer. Thus, the important distinction between the rate recovery of distribution pipeline companies and transmission pipeline companies is that regardless of the amount of gas that it delivers, the FERC-regulated transmission pipeline recovers the same dollar amount of fixed operating cost, which includes its integrity management costs, while the amount of fixed operating cost (including integrity management cost) that the distribution pipeline recovers is dependent on the volume of gas that it delivers.

Publicly-Owned Versus Investor-Owned Utilities
An important issue to note in the recovery of DIMP costs for publicly-owned utilities, e.g., utilities owned by government entities such as towns, cities, counties, and utility districts, is that many of the rate design concepts that apply to investor-owned utilities and that are described later in this paper, do not apply to publicly-owned utilities. Rates charged by publicly-owned utilities are typically established by local elected or appointed bodies such as city or town councils, county commissions, or utility boards. These bodies may or may not be required to consider the same factors that state public service commissions consider when they establish rates for investor-owned utilities. Gas rates for public gas systems are generally a purely local decision and there is no action that PHMSA or the states can take to ensure that integrity management costs will be recovered through rates.

III. THREE PRINCIPLES OF COST RECOVERY

- **Timely**
- **Complete**
- **Diversified**

The most efficient method of cost recovery related to distribution integrity management program costs is one that is timely, that recovers all prudently incurred costs, and that recognizes the unique and important distinctions among gas distribution pipelines and their state regulators and therefore, does not impose a “one size fits all” methodology on the distribution company.

Timeliness
Timeliness of rate recovery is of utmost importance in the design of rate recovery mechanisms for any costs and the timeliness of the recovery of DIMP costs is no exception. Costs that are recovered long after they are incurred cause the distribution company to bear carrying costs without the opportunity to recover these prudently incurred costs. Credit agencies frown on companies with “lag” in the recovery of their costs and assign a lower credit rating to those companies, which ultimately translates into higher rates for customers. While there are a number of rate designs that will recover DIMP program costs, not all methods recover costs in a timely fashion. Regardless of the rate design method ultimately used to recover DIMP costs, it must be one in which costs are recovered as soon as possible, and ideally, in the time period in which the costs are incurred.

Complete Cost Recovery

While timeliness is of utmost importance, recovery of all prudently incurred costs is even more critical. Incomplete recovery of costs subjects the utility to a decreased return. It is important when designing a cost recovery method that all costs related to the program are identified and assigned to the appropriate rate class for recovery. In addition, it is possible that regulatory bodies themselves may need added resources to address integrity management.

Diversified

The final component of an efficient and effective cost recovery methodology is the recognition that one size doesn't fit all cost recovery plans. Just as there are significant differences in the design of distribution pipeline systems (pipe size, operating pressures, pipe age and materials, size and growth rate of territory served, system geography, and number of interstate pipelines serving the distribution system), so there are significant differences in regulatory philosophies and concerns among the states and jurisdictions that regulate distribution systems. As with the NARUC Model State Protocols for Critical Infrastructure Protection Cost Recovery, a number of valid cost recovery techniques are available for distribution integrity management plans and there should not be a presumption that one method is better than all the others.

IV. COST RECOVERY MECHANISMS

The traditional base rate approach can be used to recover distribution integrity management program (DIMP) costs, as can several additional types of rate designs. Distribution companies that are subject to pipeline integrity management (PIM) programs have already used these tools to recover the costs of PIM programs. The mechanisms described below are not an exhaustive list, but a sampling of ratemaking solutions that could be considered by each state or regulator agency when determining what best meets their unique needs while providing for complete and timely cost recovery.

Base Rate Case

When a distribution company has sufficient test year data that can be used to forecast future costs, base rate recovery of integrity management program costs is an option. However, only a few utilities have as yet implemented PIM programs and many of those companies have not had the data necessary to fully support forecasted cost recovery. Even when the data are available, many companies have instead implemented rate trackers and deferred accounting orders, which allow better matching of future cost recovery with future cost incurrence. Several utilities that have included initial PIM costs in base rate case filings are listed below.

- In Michigan, DTE Energy's base rate case that was approved in June 2005 allowed the company to recover $7 million per year in capital dollars for such things as smart pigs, and $25 million a year for operations and maintenance expenses. DTE included PIM plan development costs, field determinations and mapping, a risk model, and training/education costs. It also included costs for pipeline integrity for 2003, 2004 and 2005**.** A noted component of the plan is that the $25 million is treated as a one-way tracker within base rates. DTE may recover from customers as much of the $25 million as is actually spent on an annual basis. If not spent, the tracker lowers the base rate or is refunded. Any amount above $25 million that DTE spends is not recoverable from customers. This technique of having a "tracker within base rates" should provide good matching of costs to revenue.

- In Kentucky, Louisville Gas and Electric's 2004 general base rate case was a settlement that did not specifically address the proposed PIM program costs. In the company's proposal, costs related to the pipeline integrity management program, amounting to $310,000, were incurred during the test year and thus were included in the proposed rates. The incurred costs were associated with data acquisition required for pipeline risk assessments, preliminary development of a pipeline integrity management plan, and evaluations of software applications supporting PIM programs. Although these were just initial costs, the timing of the rate case and the use of an historical test year limited the utility to the inclusion of only those amounts.
- Public Service Company of New Mexico (PNM) filed a general base rate case in January 2003. As part of that case, PIM costs were included among all the other costs incurred in the course of providing service on its system. The PIM costs were not singled out for special treatment, but were simply included as the general costs of doing business. The "black-box" settlement authorized PNM to increase base rates by $20 million.
- Additional companies that have filed to recover PIM costs within a base rate case include Consumers Energy in Michigan, Puget Energy in Washington, and Pacific Gas and Electric in California.

Base Rate Case Variant – Formulary Approach

A variation of the basic rate case method is the technique used by Mobile Gas. Mobile Gas' rates for recovering its total cost of service and allowed return are adjusted annually based on a formulary rate-setting mechanism approved by the Alabama Public Service Commission. Costs associated with PIM – as well as all additional operational costs - are included in the annual operations budget and are recovered through current rates established through the rate-setting mechanism. PIM costs included in the annual rate formula are supported by third-party quotes and internal work estimates. The advantage of this method is that it provides closer matching of actual costs to recovered costs.

Deferred Accounting Order

Another option is the "deferred accounting" alternative. Using this approach, the utility treats particular costs (such as those at issue here related to compliance with the Pipeline Safety Improvement Act (PSIA), which are distinct and different in nature from historic operations and maintenance costs and are not included in the utility's existing rates) in a segregated manner, thereby establishing a special deferred account. These economically material costs then are not recovered until recovery can be sought in a general rate case in the future. Generally, state authorities require a determination that the costs have been incurred prudently and have been properly accounted for. Often, these costs are deferred until the next rate case, but if one is not filed after a certain period of time, the costs are then amortized. Although the eventual ratemaking treatment of these costs is not determined at the time the order is established, a deferred accounting order implies nearly certain approval for future recovery in rates, and is so viewed by the company's auditors.

- Questar Gas in Utah received approval in June 2004 for a deferred accounting order authorizing it to establish an account for costs associated with remaining in compliance with the new federal requirements called for under the PSIA. The company estimated its costs of compliance to be between \$2 and \$5 million annually for program development, staffing, technology and other such costs. Such costs, if not deferred, would normally be charged to operations and maintenance expense in the year incurred. The commission approved Questar's request on the condition that sufficient records be maintained so that audits can be undertaken to determine future rate treatment.
- Likewise, in North Carolina in December 2004, the state commission authorized Piedmont Natural Gas to segregate incremental operations and maintenance expenses associated with compliance with PIM regulations. These costs, which Piedmont estimates will exceed \$3 million a year for the next seven years, will be deferred until Piedmont seeks recovery in a future general rate case. Resolution of any issues related to the proper amortization or the method of recovery of PIM costs was postponed until a subsequent proceeding. The deferred accounting method approved in this matter once again requires prudence and proper accounting

Rate Tracker

Instances of new and unknown costs also can be the subject of a "rate tracker" which is established by the state commission. The tracking mechanism allows the utility to recover, on a current and timely basis, costs associated with unusual circumstances or which are ambiguous in nature (e.g., natural gas prices). This "tracker" option is particularly attractive in instances of new costs for which there is no historical basis to predict costs. Rate trackers closely match actual expenses to recovered expenses.

Two Vectren utilities in Indiana, Indiana Gas and Southern Indiana Gas and Electric (SIGECO), recover pipeline integrity management costs in this way. The tracker is capped on an annual basis and allows the utilities to recover the tracked expenses up to the cap. To the extent that the utilities incur expenses beyond the tracker cap, these costs are deferred for subsequent recovery without carrying costs. If the utilities incur less than the cap in a given year, they may initiate recovery of previously deferred costs up to the amount of the cap.

- Indiana Gas (Vectren North) agreed to a settlement in October 2004 arising from a general rate case. The rate case settlement includes authorization to implement a "tracker" that will allow Indiana Gas to recover expenses caused by the PSIA requirements. The tracker first will be implemented in 2005 to recover costs deferred over the 12 months ending March 31, 2005, and is subject to an annual cap of $2.5 million. After three years, the tracker will be reviewed to see if the expenses still necessitate tracking or if, at that time, the costs have become sufficiently fixed and measurable to permit some reasonable allowance to be embedded in base rates going forward. The tracker will be distributed to all classes of customers, and Indiana Gas is required to update annually the tracker unit rates.
- At Southern Indiana Gas and Electric Co. (Vectren South) a tracker was agreed to as part of a general rate case settlement in March 2004. Similar to Indiana Gas, the tracker will be first implemented in 2005 to recover 12 months of deferred expenses. The SIGECO tracker is capped at $750,000 for the first year and $500,000 annually thereafter. As with Indiana Gas, SIGECO may seek base rate recovery of the eligible deferred costs at the three-year review of the tracker if the costs have become sufficiently fixed and measurable. SIGECO is also required to annually update the tracker unit rates.

Capitalized Cost

Under this methodology, a utility is permitted to classify pipeline integrity management costs as capital expenditures and to recover in rates the associated costs. Generally, an accounting order or a rate order of a regulator is issued to provide appropriate support for this accounting position with the utility's auditor. The advantage of capitalizing costs is that the impact on the company's financial statements is spread over several years, rather than expensed in the year the cost is incurred, and similarly, the revenue recovery is spread over several years rather than a single year. Capitalizing PIM costs stretches out the time period over which PIM costs are recovered, benefiting both customers and shareholders. When combined with recovery of carrying costs, this recovery method prevents margin erosion from regulatory lag.

- In 2004, NW Natural Gas Co. received approval from the Oregon Public Service Commission to treat PIM costs as capital costs. The costs to comply with the PSIA will be in the range of $5 million the first year and PIM program costs may range from $5 to $15 million in subsequent years, with total costs of as much as $50 to $100 million. In addition, the new pipeline integrity work is classified as capital because the PSIA obligations are required in order to continue to operate the covered sections of NW Natural's existing transmission pipeline without pressure reductions. In many instances, pipeline pressure reductions in lieu of PSIA compliance would lead to a loss of service on design days. In addition, the PSIA work will ultimately result in an extension of the useful life of the transmission lines. Thus, the commission agreed with the utility that it was appropriate to consider the compliance costs as a capital expense. The commission explained that on an annual basis the actual program costs incurred during the most recent tracking period will be used to determine the PIM revenue requirement for the relevant year. These costs will then be recovered through the company's annual PGA filing.

V. CONCLUSION

The most efficient method of cost recovery related to distribution integrity management program costs is one that is timely, that recovers all costs, and that recognizes the unique and important distinctions among LDCs and their state regulators and therefore, does not impose a "one size fits all" methodology on LDCs.

Several utilities have already incurred federally mandated transmission pipeline integrity management program costs and these utilities have used a wide variety of state approved mechanisms for cost recovery. Among such mechanisms are: rate trackers, which recover on a current basis, outside of base rates, the actual integrity management costs that distribution companies incur; rate deferment mechanisms, which identify and defer in a special account for later recovery the actual costs of integrity management programs; capitalized asset plans, in which distribution companies capitalize their integrity management costs and then recover over the life of the capitalized asset the related rate base and authorized return on those assets; recovery as a normal expense in base rates; and recovery in base rates pursuant to a formulary mechanism. Each of these mechanisms is suitable for consideration for recovery of distribution integrity-related costs, so long as the principles of timeliness and completeness of rate recovery are also recognized.

Attachment A

Integrity Management for Gas Distribution Pipelines

Strategic Options Group Report

October 14, 2005

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Acronyms

AGA – American Gas Association
APGA – American Public Gas Association
API – American Pipeline Institute
ASME – American Society of Mechanical Engineers
CFR – Code of Federal Regulations
DOT – Department of Transportation
EDPG – Excavation Damage Prevention Group
EFV – Excess Flow Valve
GPTC – Gas Piping Technology Committee
GTI – Gas Technology Institute
IM – Integrity Management
LEAKS – Leak Management Program Consisting of: Locate, Evaluate, Act, Keep Records, and Self-Assess
LDC – Local Distribution Company
NAPSR – National Association of Pipeline Safety Representatives
NARUC – National Association of Regulatory Utility Commissioners
OMB – Office of Management and Budget
RCP – Risk Control Practices Group
R&D – Research and Development
SOG – Strategic Options Group
SMYS – Specified Minimum Yield Strength
TSI – Transportation Safety Institute

Executive Summary

The mission of the Strategic Options Group (SOG) was described in the PHMSA Report to Congress as:

> Consider means by which effective risk control practices can be implemented across the broad range of distribution pipeline system operators and gather data on the costs and benefits of doing so.[24]

The group was composed of representatives of the natural gas distribution industry, state pipeline safety regulatory authorities, and the public. A list of the members is provided as Exhibit A.

The group conducted its work through a series of meetings, summaries of which are available on the distribution integrity management web site.[25] As a result of its deliberations, the SOG reached the following findings and conclusions:

- The most useful option for implementing distribution integrity management requirements is a high-level, flexible federal regulation, in conjunction with implementation guidance, a nation-wide education program expected to be conducted as part of implementing 3-digit dialing for one-call programs, and continuing research and development
- Model state legislation, guidance for mandatory adoption by states, and a prescriptive federal regulation are not considered useful options to address the question of distribution integrity management
- Model state legislation may be useful for the narrower issue of improving excavation damage prevention through implementation of comprehensive damage prevention programs including active enforcement
- A small number of elements are all that is needed to describe the basic structure of a high-level, flexible federal regulation addressing distribution integrity management. (These elements are presented graphically in Exhibit B).
- Implementation of the elements of a distribution integrity management regulation should be based on information that is reasonably knowable to an operator and on information that can be collected on a going-forward basis. Extensive historical research need not be required or expected.
- It would not be appropriate to exclude any class or group of local distribution companies/agencies from distribution integrity management requirements
- It would be inappropriate to require an operator to develop two separate integrity management programs solely to address pipe that is in the range of 20 to 30 percent SMYS if the failure mode of that pipe is similar to other distribution pipeline. Accordingly, it may be necessary to provide an option whereby pipeline at these stress levels, currently defined as transmission pipeline and subject to the

[24] Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, Department of Transportation, "Assuring the Integrity of Gas Distribution Pipeline Systems: A Report to the Congress," May 2005, page 23
[25] www.cycla.com/dimp

provisions of 49 CFR Subpart O, can be treated by distribution pipeline operators under their distribution integrity management programs. Further work is needed to define the threshold stress level at which failures would be expected to occur by rupture from latent mechanical damage.

- As part of its distribution integrity management plan, an operator should consider the mitigative value of excess flow valves (EFV)s. EFVs meeting performance criteria in 49 CFR 192.381 and installed per 192.383 may reduce the need for other mitigation options. It is not appropriate to mandate excess flow valves (EFV) as part of a high-level, flexible regulatory requirement. An EFV is one of many potential mitigation options. (One member did not subscribe to the group conclusion on this issue).
- A separate treatment of EFVs, i.e., outside of integrity management requirements, may be more appropriate.
- It would be appropriate for operators to be required to submit information periodically to PHMSA and states on a limited number of performance measures to enable the effectiveness of distribution integrity management requirements to be trended. Operators could benefit from more detailed performance measures to monitor and improve their own performance, which need not be submitted to regulators.
- The most useful performance measures at the national level would be incidents (per mile or per service), number of excavation damages per "ticket", and a redefined measure or measures related to leaks. (The SOG could not reach consensus on a particular leak measure. Possibilities include hazardous leaks, corrosion leaks, and material leaks, each per mile or per service)
- Performance measures regarding the type and amount of pipe in an operator's system and number of excavation damages would be less useful at a national level
- Considering the wide diversity among distribution pipeline operators, it would be most appropriate to rely on guidelines for the general implementation of integrity management requirements and to look to technical standards only for specific details.
- The principal benefit from implementing integrity management regulations is expected to be a reduction in the number of incidents and their consequences (i.e., deaths, injuries, and property damage)
- Any changes resulting from distribution integrity management efforts that reduce the frequency of third-party damage events will result in significant benefit to gas distribution operators
- It is likely that other benefits that can be considered other than avoided incident consequences will need to be identified.
- The costs for implementing distribution integrity management requirements will likely include costs for developing written plans, performing risk analyses, and integrating information about pipeline condition. It is expected that these activities will be required of all operators subject to the requirements.
- The costs associated with integrity management requirements will include any additional risk control practices that must be implemented and the effort to verify their effectiveness.

- Estimating costs for implementing risk control practices requires knowledge of the practices that operators are likely to need to implement or modify. That information is not now available, because of the wide diversity of operators and the programs/activities they now employ. The American Gas Association and American Public Gas Association can help provide estimates for the costs that may be associated with risk control practices once the specific practices to be considered have been defined.
- There would be value, particularly for small operators and state pipeline safety regulatory agencies, in an independent effort to collect, analyze, and disseminate information learned from operating experience throughout the industry. It is not clear at this time how such an effort might be funded.

The sections that follow provide additional information about the factors that the SOG considered in reaching these findings and conclusions.

Options Considered

Seven options were identified for implementing distribution integrity management requirements and were discussed by the Executive Steering Group at its March 16, 2005, meeting. These were:

- Option 1: Structured nationwide public education program.
- Option 2: Model State legislation, potentially imposing requirements on excavators and others outside the regulatory jurisdiction of pipeline safety authorities
- Option 3: Guidelines or national consensus standards, providing guidance to states and operators for implementing integrity management approaches
- Option 4: Guidance documents for adoption by States, similar in scope to option 3 but with the intent of states mandating use of the guidance
- Option 5: Risk-based, flexible, performance-oriented Federal regulation, establishing high-level elements that must be included in integrity management programs
- Option 6: Prescriptive Federal regulation, specifying in detail actions that must be taken to assure distribution pipeline integrity
- Option 7: Development of innovative safety technology, to provide means not now available for addressing the integrity of distribution pipelines

The Executive Steering Group identified preferences for four of the options, to be implemented either separately or in combination. These were Options 1, 3, 5, and 7.

Further consideration of implementation options and documentation of the reasons why each option was/was not selected was assigned to the SOG.

Implementation Options Selected and Expected Areas of Application

Upon further consideration, the SOG reached the same conclusion as the Executive Steering Group. Four options would each be of benefit in helping to assure integrity of distribution pipeline systems.

Option 1: Structured nationwide public education program.

This option has value in a specific area. An education program addressing the full breadth of integrity management would be too complex for public effectiveness. A program addressing external force damage would be useful but it has the disadvantage that it: (a) would address only one of the threats, (b) would be beyond the regulatory jurisdiction of state pipeline authorities, and (c) would be unreasonable as a requirement to be imposed on local distribution companies (LDC). At the same time, there would be value from such a program in reaching audiences outside the pipeline community who pose threats to distribution pipelines, and could contribute to reducing the magnitude of the single most important threat to distribution pipelines.

The SOG noted that 3-digit dialing (811) has just been approved for one-call nationally. That system will be implemented over approximately the next two years. There will most likely be a national education program associated with rolling out the new dialing system. A damage prevention message focused on gas distribution pipelines would be useful as a part of that program.

The SOG also notes that recently published requirements for public education programs (API-1162) will also provide an opportunity for improving awareness of pipeline safety issues.

Option 3: National guidelines or consensus standards, providing guidance to states and operators for implementing integrity management approaches

There is significant diversity among LDC operators in terms of size, system complexity, operating environment, and relevant threats. This diversity makes it highly unlikely that any high-level requirement, standing alone, would provide complete information for all operators regarding what needs to be done to comply. Although guidance would be valuable, the diversity of LDC systems may make it difficult to address integrity management in a single guidance document. This diversity also makes standardized approaches less useful for distribution system integrity management than was the case for gas transmission integrity management. The SOG concluded that guidelines, providing for maximum flexibility, would be the preferred means of providing guidance to most operators. More specific guidance will likely be needed for the smallest operators, as discussed further below.

Option 5: Risk-based, flexible, performance-oriented Federal regulation, establishing high-level elements that must be included in integrity management programs

This is the principal option endorsed by the Executive Steering Group (in combination with Options 3, 1, and 7). All States are required to adopt standards that are at least as stringent as federal regulations in order to maintain certification of their pipeline safety programs or agreements to exercise regulatory jurisdiction. This option thus assures uniformity in the basic approach to distribution integrity management. A federal rule, adopted by States, would provide a mandatory requirement for operator action. In many cases, and considering the cost pressures on company operations, this would be the only way to assure actions. It could also facilitate recovery of implementation costs in the rate process.

Flexibility will be important in a high-level regulation to allow situation-specific adjustments to deal with circumstances unique to individual States and operators. Operators and State regulators having jurisdiction over their systems are in the best position to decide on appropriate adjustments to their practices.

Option 7: Development of innovative safety technology, to provide means not now available for addressing the integrity of distribution pipelines

Additional research and development (R&D) to develop new approaches can be useful. PHMSA has used R&D to develop technologies that operators can choose to support their implementation of programs to improve safety performance. R&D directed at developing new tools for investigating distribution system integrity or addressing mitigating factors that can improve integrity would be useful. R&D is not, by itself, a solution to questions about integrity management, but it can contribute to an improved ability to manage integrity. One area in which work is needed is defining the threshold at which failure is likely to occur by rupture (vs. leakage) from latent mechanical damage, which in turn would help define the appropriate integrity management treatment for low-stress pipeline.

Implementation Options not selected

Option 2: Model State legislation, potentially imposing requirements on excavators and others outside the regulatory jurisdiction of pipeline safety authorities

Experience indicates that this option may not be practical for addressing the broad question of integrity management. 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 it would represent a national solution to IM concerns. For example, state legislatures generally have not adopted an available model from the Common Ground effort to prevent excavation damage.

For the narrower question of improving protection against excavation damage, state legislation may be needed. The Excavation Damage Protection Group, as part of this program, has concluded that states which actively enforce damage prevention regulations have fewer damages and improving trends. The Excavation Damage Prevention Group has concluded that enhancing enforcement is a necessary element in addressing this largest threat to gas distribution pipelines. This means new requirements enacted at the state level. Accordingly, it may be appropriate to propose model legislation for this specific purpose. Still, for the reasons described here, this option is not considered viable as a means of addressing the entire integrity management issue.

Option 4: Guidance documents for adoption by States, similar in scope to option 3 but with the intent of states mandating use of the guidance

This option is essentially the same as option 3, except it contemplates states adopting the guidance as mandatory requirements. The reasoning expressed with regard to option 3 (above) applies equally here. As with model legislation, the SOG considers that adoption likely would not occur in many states. Distribution integrity management is an issue over which States have jurisdiction, and states typically do not uniformly adopt recommended approaches. Selecting this option would thus provide only the illusion of a solution.

Option 6: Prescriptive Federal regulation, specifying in detail actions that must be taken to assure distribution pipeline integrity

A highly detailed prescriptive regulation would eliminate the flexibility that is needed to address the unique circumstances of individual States and operators. The wide range in size and nature of distribution pipeline systems makes it impractical to develop a single detailed set of requirements that could be "prescribed" to assure integrity management in an effective manner at each. A detailed prescriptive rule would be inappropriate and ineffective, resulting in many operators being required to perform tasks not appropriate for their pipeline systems. More direction is needed for many of the small operators who lack the resources to develop complicated programs on their own. This can be provided through guidance.

Elements of a High-Level, Performance-based Rule

The SOG considers the following to be a minimum set of elements for a high-level, flexible, federal rule to help assure distribution pipeline system integrity. A graphical depiction of these elements is provided in exhibit B. The SOG expects that further information and options for implementing each element would be provided through guidance and/or State requirements.

1. Development of an integrity management plan

   Each operator of a gas distribution system shall have a written plan for managing the integrity of its distribution system. The plan shall include the following minimum elements: knowledge of its infrastructure, identification of threats, assessment and prioritization of risks, mitigation of risks, measurement and monitoring performance, and reporting results.

2. Know your infrastructure

An operator must have knowledge of its natural gas distribution system including: location, material composition, piping sizes, construction methods, date of installation, soil conditions, pressure (operating and design), history, operating experience/ performance data, condition of system, and any other characteristics noted by the operator as important to understanding its system.

3. Identify threats (existing and potential)

The operator shall consider at least the following categories of existing and reasonably foreseeable threats: Corrosion, Natural Forces, Excavation, Other Outside Force Damage, Material or Welds, Equipment, Operations, and any other concerns that are important in the judgment of the operator.

4. Assess and prioritize risk

Each operator must assess the risk (the likelihood and potential consequences) and prioritize the threats that may affect safe operations.

5. Identify and implement measures to mitigate risks

The operator shall determine and implement actions it believes will reduce identified risks.

6. Measure performance, monitor results, and evaluate effectiveness

The operator shall develop and monitor performance measures, from an established baseline, to allow it to evaluate the effectiveness of its plan. The operator must re-evaluate threats (element 3) and risks (element 4) as appropriate.

7. Report results

The operator shall report a subset of its performance measures periodically to regulatory authorities.

(The report of the Risk Control Practices Group provides information about specific measures that can be considered to reduce risk. The SOG findings regarding measures that should be considered for reporting are discussed below).

Collectively, these elements are intended to establish a program to reasonably assure the integrity of distribution pipeline systems on a going-forward basis. There is no intent that extensive historical evaluations of pipeline integrity or factors that could affect integrity be required to fill in any blanks. An operator's program should be based on historical information reasonably available and knowable without such evaluations.

For example, "history" is one of the factors included in what an operator should know about its system (element 2, Know Your Infrastructure). This is intended to reflect a need to review/utilize information about historical events and conditions that could have an effect on future integrity of the pipeline system and that is reasonably available. It is not intended that an exhaustive search of past records or non-operator historical databases be required.

Similarly, "condition of soil" (as a factor in element 2) is not intended to require extensive determination of soil chemical composition. Instead, it is intended to reflect a need to collect (going-forward) information that is reasonably available regarding the nature of the soils in which pipeline is laid. Are there large rocks? Was there a history of mudslides? Does the soil cause an unusually corrosive environment?

"Condition of system" is intended to reflect the existing state of pipeline integrity for the system, including baseline values of any performance measures the operator designates in its integrity management plan.

Once an integrity management plan is developed, operators would be expected to align their future practices for data gathering to collect information relevant to that plan that reasonably becomes available during the course of future work. As an example, operators might collect information from future excavations concerning the "condition of soil" in which pipe is located. Here again, operators would be expected to collect only general information when there is something present worthy to note as a potential risk or to be considered for future design parameters, rather than detailed chemical composition, etc, unless specific circumstances or threats faced by the operator dictate the need for more detailed information. This would be intended to improve the quality of information considered within the integrity management program, and thus the decisions made within that program, again without a requirement for extensive new data gathering activities.

Applicability to Different Classes of Operators

The group discussed whether any classes of operators should not be subject to any potential distribution integrity management requirements. At its first meeting, the SOG had posed a question to the Data group to try to determine if incident data suggested a "threshold" below which further actions to improve integrity might not be needed. The Data group evaluation concluded that there was not any obvious threshold.

The American Public Gas Association (APGA) commented during a panel discussion at the June 2005 meeting of the Technical Pipeline Safety Standards Committee that it did not want operators at any size level to be excluded from integrity management requirements. They are concerned that this would send the mistaken impression that these operators are being held to a less stringent safety standard. At the same time, APGA notes that smaller operators have fewer resources to develop integrity management plans and processes and would like more detailed guidelines that they can follow to comply with distribution integrity management requirements.

The welding qualification rule (49 CFR §192.227) provides a potential model. The rule refers to API Standard 1104, but also references 49 CFR 192 Appendix C, which provides specific requirements that operators having only low-stress pipeline can follow to comply. Such an option, if provided, should be available to all operators who meet the conditions and limitations within any appendix (e.g., for welding, low-stress pipeline). Such operators would have the option of adopting specific procedures/requirements detailed in an Appendix to 49 CFR or developing their own programs, which could allow for additional flexibility.

The SOG also considered whether the threshold for defining transmission lines could be raised from 20 to 30 percent SMYS, for purposes of integrity management. (No consideration was given to changing the functional portions of the transmission line definition). Lines operated by distribution companies that operate at greater than 20 percent SMYS are currently subject to the transmission IM rule. The failure mode for those lines is generally leakage, similar to distribution pipelines. The transmission IM rule already acknowledges that different treatment is appropriate, by allowing for a "low stress assessment" for transmission lines operating below 30 percent SMYS. It would seem more appropriate to treat those lines in distribution integrity management programs for companies that will also have distribution pipeline subject to those requirements.

The group concluded that it would be inappropriate to require an operator to develop two separate integrity management programs solely to address pipe that is in the range of 20 to 30 percent SMYS if the failure mode of that pipe is similar to other distribution pipeline. There are some transmission pipeline operators that operate pipeline segments in this range but who have no distribution pipelines, and these companies should be able to continue to treat that pipeline under their transmission integrity management programs. In addition, there could be benefits even to companies that must maintain two programs in deciding which plan is appropriate to treat this pipeline.

The technical basis for considering this low-stress pipeline under distribution integrity management requirements is that the failure mode of low-stress piping is leakage, like distribution pipelines, rather than rupture. Technical work has been done by the Gas Technology Institute (GTI) to define where the failure mode transitions from leakage to rupture. This work, reported in GTI Report DRI-00/0232, published in March 2002, indicated that the rupture transition for corrosion defects can be taken as 30 percent of SMYS. The GTI report indicated, however, that work on the threshold for delayed mechanical damage was incomplete, and the threshold was then taken to be 25 percent. Further work is needed to define this threshold.

Subject to resolving the question of the delayed mechanical damage threshold, the group agreed on the following options:

1. Redefine transmission pipeline, at least for the purposes of IM, to be limited to pipelines operating at greater than 30 percent SMYS (or whatever lower threshold is determined for transition from rupture to leakage as a failure mode), leaving the functional portions of the transmission pipeline definition unchanged,

2. Give operators the option to treat lines operating at less than 30 percent SMYS (or below a lower technically-determined damage transition threshold) or non-ferrous pipeline under distribution management programs, or
3. Provide the option described in #2, but only after the completion of a baseline transmission integrity management assessment for pipelines currently meeting the definition of transmission pipeline.

Other than this suggested change, the group concluded that any distribution integrity management requirements should be applicable to all distribution operators, regardless of size. Guidelines can be used to address options for implementation that would be less burdensome for smaller operators.

Strategic Approaches to Requirements for Excess Flow Valves

Excess flow valves (EFV) are an option to mitigate the consequences of catastrophic failures of natural gas service lines. They do not provide any protection from non-catastrophic leaks. The Executive Steering Group directed that SOG consider requirements for installation of EFVs as part of integrity management regulations.

The SOG discussed potential strategic approaches to including EFVs in distribution integrity management requirements. The group considered potential ways in which a requirement for EFVs could be formulated. Options include a specified decision model (which could be incorporated in guidance) and a requirement similar to that for automated/remotely operated valves in the transmission integrity management rule. In the latter, operators are required to install valves if they determine, based on a risk analysis, that they are needed to protect the public in the event of a natural gas release. The SOG would envision a risk assessment for this purpose being conducted on a system basis (or portion of system) rather than on a service-by-service basis. The transmission rule specifies a number of factors that operators must consider, at a minimum, in the analysis supporting their determination. For an EFV requirement in the context of distribution integrity management, decision support criteria likely also will be needed regardless of the position taken in a regulation. This information could be included in guidance.

There has been some discussion of requiring operators to submit documentation to regulatory authorities regarding their decision on use of EFVs. If such requirements are to be included in integrity management regulations, the SOG prefers a formulation that refers to an evaluation or determination, similar to the language in the gas transmission integrity management rule, rather than a requirement to “justify”. Documentation of an operator’s decision will be part of their integrity management plan, and the SOG thus questions the need for separate documentation – for this, or any other individual element. In any event, operators who voluntarily install EFVs should not be required to submit information concerning their decisions. Any requirements for evaluation/justification/ documentation should be related only to operator decisions <u>not</u> to install. Operators who voluntarily decide to install EFVs on all new and replaced services where conditions are suitable should be subject to no new EFV requirements.

As a result of its discussion, the group agreed to the following finding regarding EFVs:

> *As part of its distribution integrity management plan, an operator should consider the mitigative value of EFVs. EFVs meeting performance criteria in 49 CFR 192.381 and installed per 192.383 may reduce the need for other mitigation options.*
>
> *It is not appropriate to mandate excess flow valves (EFV) as part of a high-level, flexible regulatory requirement. An EFV is one of many potential mitigation options.*

SOG believes that a separate treatment of EFVs may be more appropriate, and that this issue should not be treated within distribution integrity management requirements. An operator could still receive some "credit" in the context of integrity management for having EFVs, but it is unclear how this might be provided.

One member's alternate view is that installation of EFVs should be mandated on all new and replaced service lines operating above 10 psig where conditions are suitable.

Performance Measures

Performance measures, considered on a national basis, can serve several purposes:

1. Foster increased safety through reducing incidents
2. Demonstrate value of distribution integrity management efforts
3. Illustrate trends
4. Drive safety behaviors
5. Demonstrate progress
6. Increase public confidence

In the long term, national measures may identify a need to modify the regulations further.

The Risk Control Practices Group and the Excavation Damage Prevention Group have both considered possible performance measures appropriate to their areas of focus. In both cases, the groups considered both national performance measures (i.e., appropriate to report to PHMSA/states) and internal measures (i.e., to be used internally to a company). Measuring performance is important to individual operators to obtain information on whether their integrity management activities are being effective. Operators can adjust their actions, e.g., to increase or decrease specific activities or to refocus priorities, as needed. This is the primary purpose of internal measures, which are an integral part of measuring/monitoring/evaluating effectiveness (see "Elements of a High-Level, Performance-based Rule" above).

The SOG focused its attention on the suggested potential national performance measures described in the following table:

Suggested National Performance Measures Evaluated

Suggested Measure	Found Useful	Considered Less Useful
Incidents (per mile or per service)	X	
Type and amount of pipe in an operator's system		X
Number of excavation damages		X
Number of excavation damages per "ticket"	X	
A measure or measure related to leaks[26]	X	
Progress in implementing integrity management and leak management		X

The Risk Control Practices Group (RCP) has concluded that the number of incidents, in total and per mile (or per service), would be a useful national measure. The SOG agrees. Incidents are where adverse safety consequences occur. Monitoring the number of incidents is a direct indication of the potential prevalence of those consequences, and reducing that number will have the effect of improving safety. Thus, this measure accomplishes several of the purposes listed above and is a primary and direct measure of the safety improvement sought through integrity management programs. Current regulations already require that incidents, and data that can be used to normalize their occurrence by mile (or service), be reported. The number of incidents occurring is low enough that it is difficult to measure statistical trends. Thus, additional national measures are likely needed to generate data that can be used to evaluate trends and demonstrate progress.

The RCP has also concluded that the type and amount of pipe in an operator's distribution system would be a useful national measure. Such a measure could fulfill some of the purposes listed above. It could illustrate trends, for example, toward greater use of "state of the art" pipeline materials, thus demonstrating progress. It could be argued that it could drive safe behavior in that it could influence operators to replace older pipe with newer materials. At the same time, though, the relationship to safety is not direct. Older materials are not necessarily unsafe. Similarly, local circumstances have produced instances in which problems with newer materials have created situations with potential safety significance. Behavior driven by a national performance measure toward replacing older materials just because they are old would not necessarily advance safety, and could actually be detrimental. Use of this measure would not be intended to imply a requirement to replace piping. Operator integrity management plans may include replacement programs if their risk assessments indicate they are appropriate.

The Excavation Damage Prevention Group (EDPG) has concluded that national reporting addressing the frequency of damage events would be useful. The SOG agrees.

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[26] The SOG did not reach consensus on the particular leak measure to be used, due largely to inconsistencies in how leaks are presently reported. A more focused treatment is likely needed, to provide information useful in evaluating integrity management performance. Possibilities include hazardous leaks, corrosion leaks and material leaks, each per mile of service.

Excavation damage is the most significant cause of gas distribution incidents and related safety consequences. Reducing the frequency of such events would improve safety. Measuring these events on a national basis could help to drive behaviors that result in such a reduction. Over time, this measure could illustrate trends (potentially providing a basis for further behavioral changes) and demonstrate both the value of distribution integrity management efforts and an improvement in safety.

The EDPG has suggested that appropriate national measures could include the total number of damages (as defined by their efforts and described in their report) or as the ratio of the number of damages to the number of locate tickets. The SOG considers that an approach using the ratio of damages to tickets would be most useful. Total damages is not useful as a measure, since it will likely change with changes in the level of construction activity.

The SOG also concludes that some performance measure related to the occurrence of leaks on pipeline systems is needed. Leaks can represent instances in which pipeline integrity has been compromised, and public credibility is likely to be difficult to gain without recognizing that fact. At the same time, leaks differ in nature and it has been difficult to reach a consensus about how they should be treated for the purpose of distribution integrity performance measures. The SOG concludes that the data currently reported concerning leaks (i.e., annual report totals of leaks removed and leaks scheduled for repair) will not be particularly useful as performance measures for integrity management due to inconsistencies in reporting.

Operators generally grade leaks in accordance with significance. GPTC provides guidance for this purpose, but not all operators use the GPTC system. Current federal regulations require that hazardous leaks (GPTC class 1) be repaired. Operators schedule other leaks for repair, where there is concern that they could become hazardous or as part of pipeline improvement programs. However, many leaks are extremely small and have no potential for creating a hazard. Such leaks could be referred to as “nuisance leaks”. Counting them for performance measurement purposes could be counterproductive. It could influence behaviors in a manner that would reduce the reported number of leaks but which would not result in any improvement in safety. In fact, it could result in a decrease in safety if efforts to reduce leaks having a potential to become hazardous (i.e., GPTC class 2) are curtailed in favor of actions that would have a greater effect on reducing the overall total number of leaks.

If leak data is to be used as an integrity management performance measure, additional guidance or further discrimination will be required to assure that the reported data is meaningful, consistent, and useful. Reporting the number of hazardous leaks repaired during a year could be one option. This would avoid intrusion and unintended impact on operator programs to address non-hazardous leaks and would obtain information on those with the greatest integrity (and safety) significance. It may require additional guidance to assure consistency in grading leaks as hazardous. Another alternative could be to consider hazardous leaks along with leaks caused by corrosion or material integrity issues. This would exclude insignificant leaks such as those associated with threaded couplings, which represent a significant portion of "nuisance" leaks and are not significant to safety.

The SOG did not reach consensus on a specific leak measure to be used.

The RCP has also concluded that measures of operator progress in implementing integrity management requirements and leak management programs (e.g., LEAKS) would be useful. The SOG agrees that these measures could be useful in demonstrating progress towards implementing any new requirements. Their usefulness would be short-lived, however. New PHMSA regulations typically include implementation deadlines. Once those deadlines have passed, measures indicating the number of operators who have implemented a requirement lose their utility. At best, then, these measures will only be useful in the short term.

It is important to remember, in any event, that performance measures are not an end in themselves. They are intended to support implementation and oversight of an integrity management process. To minimize additional reporting burden, SOG considers that any reporting requirement associated with integrity management performance measures should be consolidated with other reports required to be submitted to regulatory authorities (e.g., annual reports).

Guidance

There is general agreement that some form of guidance will be needed for implementing distribution integrity management requirements. The question is: which organization is best suited to develop that guidance?

The Gas Piping Technology Committee (GPTC) has historically developed guidelines for gas distribution operators to use in implementing 49 CFR Part 192, and would be expected to do so for any new distribution integrity management requirements included in that part. Historically, GPTC's position has been that its guidelines should not be relied upon in any manner in enforcement activities. PHMSA experience also indicates that the American Society of Mechanical Engineers (ASME) would constitute a new committee, with members having expertise specifically related to the technical subject to be considered (here, distribution integrity) whereas GPTC may use already-established committees that may lack representation from some industry segments (e.g., small operators).

Industry members of SOG see sole reliance on ASME as inappropriate. Their documents are technical standards. They are not always applicable, given the broad range of technical circumstances in gas distribution systems. In addition, ASME standards do not usually provide options, and an operator cannot "pick and choose" among the provisions of a standard. They become "standard".

In the case of distribution integrity management, and to accommodate the wide diversity among natural gas distribution operators and systems, significant options and choice will likely be needed. The SOG thus agreed that it would be most appropriate to rely on guidelines for the general implementation of integrity management requirements and to look to technical standards only for specific details.

The SOG discussed whether appropriate guidelines might be incorporated into an appendix to the rule, rather than being developed by an outside organization. This option is preferred by NAPSR/NARUC members. Industry members see this as problematic. They reported that many in the industry consider that any guidance included in the Code of Federal Regulations must be treated like a rule, with compliance required, despite the PHMSA position that appendices are not enforceable. This would require that any guidance included in an appendix remain at a high level. Providing more detailed guidance, likely to be needed, would then remain a problem.

This is particularly an issue for the smallest operators. The SOG understands that small operators do not want guidance for a process, to develop a program, etc. The smallest operators have very limited technical resources, and they want to be told specifically what to do. Historically, it has been possible to do this in rules (including, for example, specific welding qualification requirements in Appendix C to Part 192). Here, though, the Executive Steering Group has concluded, and the SOG concurs, that a distribution integrity management rule should not be prescriptive. Step-by-step guidelines can be included in guidance, but small operators will want to be assured that compliance with the guidelines will be recognized as compliance with the rule.

The SOG reached the following findings concerning guidance:

1. *Support for implementing flexible distribution integrity management requirements would be most useful in the form of guidelines.*
2. *Standards, while not considered appropriate for the general implementation guidance, could be useful for specific technical issues where more detail is needed.*
3. *The SOG took no position on which organization should be called on to develop guidance.*

Cost-Benefit

All significant new federal rules must be justified by a “regulatory analysis”, the principal component of which is a cost-benefit analysis. This analysis must be accepted by the White House Office of Management and Budget (OMB) before the regulation can be published. The regulatory analysis must describe the options considered, including a “no action” option, and must provide a brief description of why the options not pursued were dropped. SOG activities, as documented above, provide a basis for this discussion.

The regulatory analysis must be performed after a rule is drafted, since it must be based on the requirements imposed by the rule. A rule will not be drafted until phase 2 of this program, by PHMSA, and the requirements that it might include are therefore unknown at this time. Thus, the SOG could not perform a cost-benefit analysis. Rather, SOG sought to identify categories of benefits and costs that would be appropriate for consideration, and to help identify sources of data that PHMSA will be able to use for that purpose.

For distribution integrity management, the principal safety benefits are expected reductions in the number of incidents and in their consequences. DOT regulatory analyses convert such reductions to monetary values using standard assumptions (currently $3.1M per death averted and $517,150 per serious injury averted and regularly adjusted for inflation). PHMSA typically uses the historical incident record, estimates the reduction expected to occur as a result of a new rule, and calculates a "benefit" based on the averted consequences. In the previous integrity management analyses, the contributions from averted deaths and injuries have been significantly larger than those from averted property damage.

For the earliest integrity management rules, those addressing hazardous liquid pipelines, the PHMSA regulatory analysis discussed benefits largely in qualitative terms. For the gas transmission IM rule, OMB required a much more rigorous quantitative treatment. PHMSA found that the benefit derived from averted incident consequences was insufficient, representing only about 20 percent of estimated costs. PHMSA considered several other benefits expected to result from the rule.

Avoiding an accident with very high consequences was a major contributor. This "benefit" is based on the presumption that the historical record does not include the worst accidents that could occur. An accident occurring in a location, or under circumstances, different than those in the historical record could result in much higher consequences. For the gas transmission rule, the economic consequences in terms of increased cost of gas in California following the Carlsbad accident and resulting transmission line shutdown were used to estimate the magnitude of significant consequences that might be avoided. For gas distribution, this factor is not likely to be appropriate. Unlike transmission, little mileage of gas distribution pipeline is in rural areas. The historical incident record includes incidents that have occurred in densely populated urban locations.

The gas transmission analysis also included consideration of expected waivers that would preclude the need for operators to replace pipe when class locations increase. This benefit was based on the presumption that activities being taken to assure pipeline integrity, and the resulting improved knowledge of pipeline condition provided to the operator and PHMSA, would make it more likely that waivers will be issued allowing operators to continue operating without pressure reduction or pipe replacement after some class location changes. Class location requirements are not a factor for distribution pipelines, and this "benefit" would not be a factor for distribution integrity management.

Also for the gas transmission analysis, PHMSA estimated a benefit from quicker return to service following a post-incident shutdown of a transmission line. PHMSA reviewed its historical record for how long orders to shut in a line, or to operate it at reduced pressure, were in effect. PHMSA expects that the improved knowledge of pipeline condition will allow that time to be reduced in the future, since most of the activities conducted during the effectiveness of past orders and used to support lifting those orders has consisted of additional work to assess pipeline integrity. In the case of gas distribution, systems are seldom shut down or required to operate at significantly reduced pressure for any extended period, even following an incident, because such action would result in gas delivery to customers being curtailed. In addition, the nature of incidents on gas distribution systems also tends to be more readily determined than is often the case for gas transmission pipeline incidents.

Any changes resulting from distribution integrity management efforts that reduce the frequency of third-party damage events will result in significant benefit to gas distribution operators. Operators must respond to instances in which damage to distribution pipeline facilities has occurred or has potentially occurred as a result of excavation damage. The typical cost to an operator to respond to and evaluate such an event is approximately $500. A major reduction in the number of such events thus could have significant total benefit.

In terms of benefits, the SOG agreed that preventing something proactively is usually less expensive than reacting to an event. Pipe replacement programs could result in reduced maintenance costs, particularly since replacement of steel pipe by plastic would reduce costs associated with cathodic protection. It will be difficult to estimate the magnitude of these savings, and whether they outweigh the initial capital investment, however, and industry members expect that they will be very small, especially in the near term. The group agreed that it is very difficult to estimate benefits at this time due to lack of knowledge of what, specifically, will be done.

Improved knowledge of operator pipeline systems will be an intangible benefit that should result from implementing a distribution integrity management rule. Such intangibles have proven difficult to quantify in the past, however, and this case is unlikely to be any different.

For distribution integrity management, it is likely that other benefits that can be considered will need to be identified.

Costs are estimated in PHMSA analyses based on actions that operators are expected to take as a result of the rule, taken as an increase above a baseline representing actions already in place. Thus, for example, costs to conduct pipeline assessments under the other integrity management rules were estimated based on the assumption that operators would continue to perform assessments in the absence of a rule at the rate they were performing them prior to the rules' being issued. The costs for the additional testing to raise testing rates to those required under the rule were the costs considered in the analyses.

In each of the preceding integrity management rules, PHMSA considered the costs to operators to develop IM plans, to maintain those plans, to re-align their data systems to permit data integration, and to perform data integration on an annual basis. Similar activities are likely to be required for distribution integrity management. The major component of costs for the earlier rules was conduct of integrity assessments using in-line inspection, pressure testing, or direct assessment (for gas transmission pipelines). At this point, no analogous new requirement has been identified for distribution integrity management. (49 CFR 192.613 specifies existing monitoring requirements with similar purpose).

Discussion by the SOG noted that a flexible rule, such as is anticipated for distribution integrity management, will lead to options for actions by the operator. The Risk Control Practices Group has concluded that there are significant differences among operators in terms of present implementation of needed/selected risk control practices. Some have already implemented practices, and may need to make only minor adjustments to current practices, while others may not have implemented practices beyond the federal code minimum requirements. Most are somewhere in between. The Risk Control Practices Group concluded that it did not have information to reach conclusion on the current state of implementation of risk control practices likely to be needed as a result of distribution integrity management requirements. This is likely to make estimation of costs more difficult than it was for the other IM rules, in which assessments (a consistent action by all operators) were the principal component of costs.

The SOG agreed that industry likely has the best information about the cost of implementing specific risk control practices. AGA and APGA agreed that they could provide cost estimates if specific practices for which this information is needed were identified. As discussed above, that identification is not possible at this time. PHMSA should seek information from AGA/APGA if and when it identifies specific practices that must be considered in a regulatory analysis supporting integrity management requirements.

For EFVs, estimating costs will require an estimate of how many operators are not now installing EFVs and how many are likely to change to doing so as a result of distribution integrity management, which information is not now available.

Operating Experience Review

An important element of each of the other IM rules is gathering and integrating information about issues that could affect pipeline integrity. This includes learning about new threats or unexpected circumstances that could change the likelihood of threats previously analyzed. Gathering this information can be difficult, since it involves knowing of events that may occur on other operator's pipeline systems. This could be particularly difficult for small distribution operators, who lack the staff to track industry experience actively at a detailed level.

The nuclear power industry has a program to perform a similar function of gathering and analyzing operating experience. That program involves a centralized staff, supported by the industry, which gathers information about operating events, analyzes that information, identifies significant new information requiring dissemination, and then provides information to all nuclear power plant operators. The information provided is summarized in a manner that allows operators to identify whether a problem/issue is applicable, to understand it at a summary level, and to know where to go to get more detailed information.

The SOG considered whether a similar program was practical for the distribution industry and whether it would add value. The group concluded that there would be of value, particularly for small operators. NAPSR/NARUC members noted that state program managers would also benefit from such a program. State regulatory programs, like small operators, also have limited resources and cannot expend significant efforts following operating experiences in other states.

Touchstone Energy, an alliance of electric cooperatives, provides a similar function benefiting small electric utility operators who become members.

A similar function is also currently provided in the gas distribution industry through periodic (usually annual) meetings sponsored by state regulatory programs. These include a review of new developments within the state, and to some extent from outside the state. (TSI participates in many such meetings). SOG members have found that these meetings are very effective. Illinois had such a meeting recently which was attended by many operators, including small municipal operators. It is unclear, though, whether such an approach would be practical in other states or on a long-term basis. The experience of other states indicates that the smallest operators, those who might benefit most from a sharing of operational experience, do not attend annual meetings.

The group was uncertain how such a program could be supported. The larger operators have resources, but those resources are fully engaged. Not all utilities belong to the trade associations (e.g., APGA represents approximately 600 of 1000 municipals). It would be similarly unlikely that all operators would join any consortium intended to provide this service (i.e., following the Touchstone Energy model). The group agreed that information would likely need to come from state regulatory programs in order to be most effective, since operators must pay attention to letters from their regulator. At the same time, the state programs do not reliably get information about operating events, and lack the resources to investigate, analyze, and summarize them.

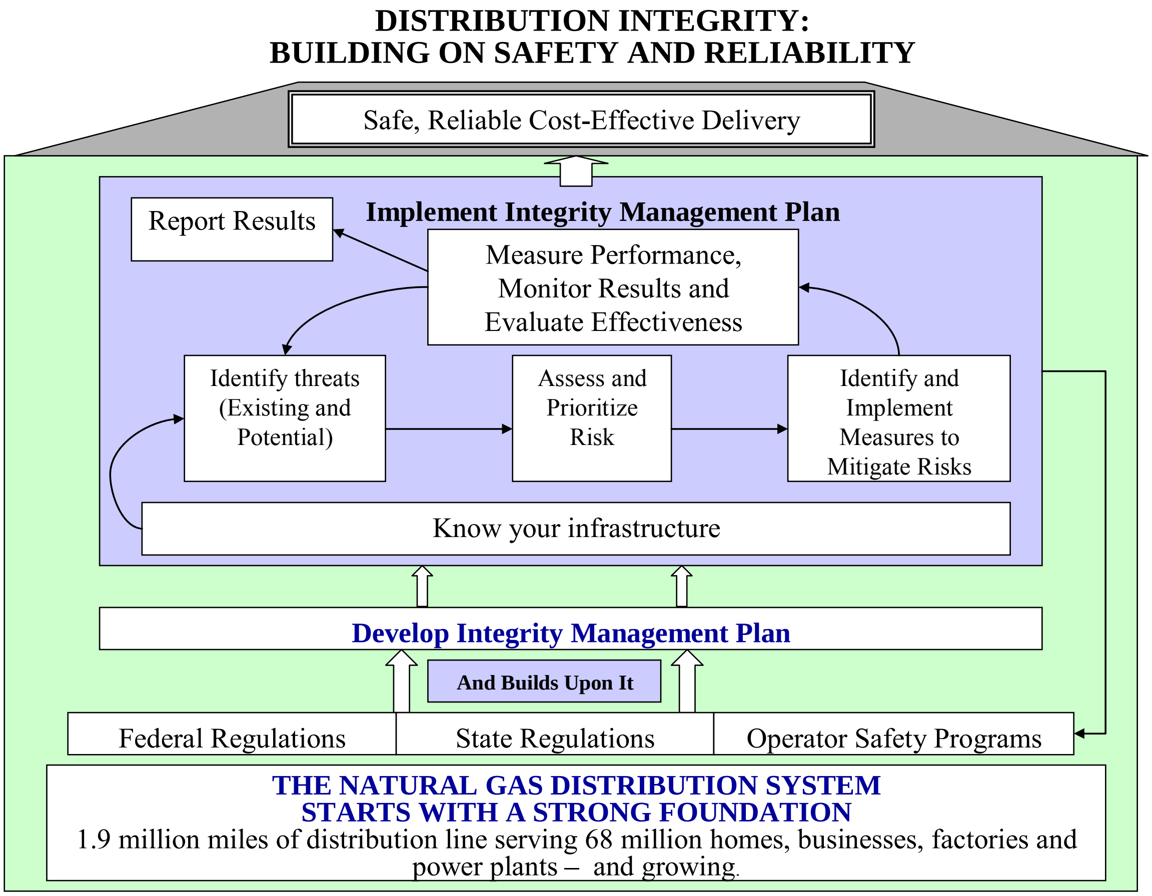
The SOG agreed that the Gas Technology Institute (GTI) would be a logical organization in which to house such a function. GTI is independent, neither regulator nor operator, has technical expertise, and is widely respected within the industry. Funding of such a program would be required for GTI to undertake one. PHMSA could provide funding through a grant program, direct contract, or similar vehicle. Data collection could involve AGA, AGPA, local gas associations, etc, who could provide “scrubbed” information (i.e., not identifying companies involved) from their roundtable programs.

Exhibit A

Strategic Options Group
Membership

Jim Anderson (Chair)	North Carolina Utilities Commission
Chris Beschler	Yankee Gas
Gary Gibson	City of Springfield
Rick Kuprewicz	Accufacts, Inc.
Bob Leonberger	Missouri Public Service Commission
Mary McDaniel	Railroad Commission of Texas
Kris Nichols	Nicor Gas
Mary Palkovich	CenterPoint Energy
Roger Huston	Cycla Corporation (contractor)

Exhibit B


DISTRIBUTION INTEGRITY:
BUILDING ON SAFETY AND RELIABILITY
Safe, Reliable Cost-Effective Delivery
Report Results
Implement Integrity Management Plan
Measure Performance, Monitor Results and Evaluate Effectiveness
Identify threats (Existing and Potential)
Assess and Prioritize Risk
Identify and Implement Measures to Mitigate Risks
Know your infrastructure
Develop Integrity Management Plan
And Builds Upon It
Federal Regulations
State Regulations
Operator Safety Programs
THE NATURAL GAS DISTRIBUTION SYSTEM
STARTS WITH A STRONG FOUNDATION
1.9 million miles of distribution line serving 68 million homes, businesses, factories and power plants – and growing.

Attachment B

Integrity Management for Gas Distribution Pipelines

Risk Control Practices Group Report

October 14, 2005

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Acronyms

ANSI – American National Standards Institute
ASA – American Standards Association
ASME – American Society of Mechanical Engineers
ASTM – American Society for Testing and Materials
AWWA – American Water Works Association
CFR – Code of Federal Regulations
CNS – Canadian National Standard
DOT – Department of Transportation
DUI – Driving Under the Influence
EFV – Excess Flow Valve
GEOP – Gas Engineering and Operating Practices
GIS – Geographic Information System
GPTC – Gas Piping Technology Committee
GTI – Gas Technology Institute
LDC – Local Distribution Company
MEA – Midwest Energy Association
NAPSR – National Association of Pipeline Safety Representatives
NARUC – National Association of Regulatory Utility Commissioners
NFPA – National Fire Protection Association
NGA – Northeast Gas Association
NTSB – National Transportation Safety Board
O&M – Operations and Maintenance
PHMSA – Pipeline and Hazardous Materials Safety Administration
PVC – Polyvinyl Chloride
RCP – Risk Control Practices
R&D – Research and Development
SCADA – Supervisory Control and Data Acquisition
SGA – Southern Gas Association
SIRRC – State Industry Regulatory Review Committee
WEI – Western Energy Institute

Introduction

There are significant differences between distribution and transmission pipeline systems[27], as well a significant diversity of distribution systems subject to 49 CFR 192, "Transportation of Natural and Other Gas By Pipeline: Minimum Federal Safety Standards ("49 CFR 192," "Part 192" or "regulations").[28] This necessitates a unique approach to distribution integrity management by the Risk Control Practices Work Group.

One of the methods employed in this effort was to review existing materials available to operators which may be of assistance in developing integrity management programs. Those existing materials are addressed in the exhibits.

Three essential elements described by the DOT Inspector General formed the basis for our work:

- Understanding the infrastructure (System Knowledge),
- Identifying and characterizing the threats (Threat Analysis), and
- Reducing risks through prevention, detection and mitigation (Risk Control Activities).

This report addresses how these elements relate to existing safety and integrity rules, regulations and operator practices, such that the overall process of the safe, reliable and cost effective operation of the distribution infrastructure remains a controlled process with continuous improvement in safety performance measures. This could provide a framework for developing a documented proactive approach to safety improvement.

Operators have historically performed various activities to monitor and maintain the integrity of distribution lines as required by the Federal Regulations and state codes, where applicable, and many operators exceed the minimum requirements of the Regulations.

While a high level, risk-based, flexible federal rule on distribution system integrity is anticipated, each operator will need to provide the details as they relate to its particular operation. It is expected that each operator will need to develop a written program to execute the integrity management principles outlined in this report.

While excavation damage to distribution systems components is the major cause of incidents, deaths and injuries, this threat was assigned to the Excavation Damage Work Group. Therefore, this report, for the most part, does not address the excavation damage issues and such issues were referred to that group.

See Exhibit A for a roster of members of the Risk Control Practices Work Group

[27] "Assuring the Integrity of Gas Distribution Pipeline Systems," Report to the Congress, May 2005, Submitted by Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, pp. 12-17.

[28] Ibid, pp. 5-7.

Findings

General Findings

4. The Pipeline and Hazardous Materials Safety Administration (PHMSA) plan for a "high level, risk-based, performance-oriented Federal regulation"[29] is supported by the following:
   - 4.1. The elements necessary to implement a distribution integrity management program have been identified
   - 4.2. Methods exist for operators to develop the elements
   - 4.3. Operators may need additional guidance materials to aid in utilizing the existing methods, procedures and practices to complete their development of their distribution integrity management program
5. Since the entire distribution will be covered by the proposed distribution integrity management plan, there is no need to identify high consequence areas or identified sites.
6. There are no major areas of 49 CFR 192 that need to be changed to address distribution integrity management, with the exception of a high-level, risk-based, flexible performance regulation to require a written distribution integrity management plan by the operator, although some incidental revisions may be needed to avoid duplication or conflict. The requirement should be for a broad framework of risk-based actions to address those areas where the risk to public safety is the highest. There is a need for additional guidance materials to assist some operators in developing their integrity management programs.

Specific Findings

Findings are identified by task number and sequentially (i.e., Finding 2-3 is the third finding related to task 2). See page 5 for a list of the seven Risk Control Practice tasks.

1-1 A distribution integrity management program should consider the threats identified in the Pipeline and Hazardous Materials Safety Administration (PHMSA) Annual Distribution Report, PHMSA Form 7100.1-1 as "Cause of Leaks" in Part C:

1	Corrosion	5	Material or welds (Construction)
2	Natural Forces	6	Equipment
3	Excavation	7	Operations
4	Other Outside Force	8	Other

2-1 The distribution system characteristics must be identified.
2-2 The threats applicable to the system must be determined.
2-3 There is insufficient data regarding vehicle damage to gas facilities and other outside forces affecting gas facilities to develop a coherent understanding of

[29] Ibid, p. 3.

the nature of the problem, and therefore, it is not possible to develop strategies to address this issue. It is an area where additional data needs to be developed.
2-4 The threats applicable to the system must be prioritized using risk control principals where risk = likelihood * consequence.
2-5 Operators may need guidance on how to characterize their system, identify the threats and to prioritize the threats.
2-6 Since the entire distribution will be covered by the proposed distribution integrity management plan, there is no need to identify high consequence areas or identified sites.

3-1 Risk control practices exist that can be used to address the integrity of distribution systems.
3-2 One risk control practice is an effective leak management program, the essentials elements of which are:

6) ***L*****ocate** the leak,

7) ***E*****valuate** its severity,

8) ***A*****ct** appropriately to mitigate the leak,

9) ***K*****eep** records, and

10) ***S*****elf-assess** to determine if additional actions are necessary to keep the system safe.

3-3 Operators may need guidance on the application of available risk control practices to their systems.
3-4 Operators should consider the use of excess flow valves (EFVs) as a risk control practice to be used where appropriate.

4/5-1 Current design, construction, installation and initial testing regulations should be effective in providing for integrity of the distribution facilities that are being installed today,
4/5-2 Current operating and maintenance sections (including Subpart I of 49 CFR 192) should be effective in providing the elements necessary to maintain the integrity on distribution lines,
4/5-3 Part 192, specifically §192.605 and 192.613, does not convey the concept of a risk-based distribution integrity management process that includes gathering system knowledge (surveillance), identifying trends, analyzing and prioritizing integrity threats and controlling the integrity related risks by prevention, detection and mitigation activities.
4/5-4 Part 192 needs a regulation that specifically requires a distribution integrity management program that includes the following elements:

1 The operator develop a written program plan that describes how it manages the integrity of its distribution system and focusing on how it will satisfy the requirements below. As operators develop formal integrity management programs, they will be guided both by federal and state requirements, as well as by their own analysis of their systems.

2 The operator identify threats applicable to its system.
3 The operator characterize the relative significance of applicable threats to its piping system.
4 The operator identify and implement appropriate risk control practices (or modify current risk control practices) to prevent, and mitigate the risk from applicable threats consistent with the significance of these threats.
5 The operator develop and monitor performance measures to allow it to evaluate the effectiveness of programs implemented.
6 The operator periodically evaluate the effectiveness of its program and make adjustments dictated by its evaluation.
7 The operator periodically report to the jurisdictional regulatory authority a select set of performance measures.

4/5-5 Part 192 has some areas where minor changes would result in some improvements s relates to distribution integrity management issues (see Task 4 and Task 5, below).

4/5-6 Some of States have requirements or programs related to distribution integrity management that exceed those of Part 192 and cover the following areas:

a Pipe Replacement - Mains
b Pipe Replacement – Services and Appurtenances
c Leak Management including leak response time and backlogs of scheduled leak repairs
d Damage Prevention
e Corrosion Control

4/5-7 State requirements or programs exceeding Part 192 are often tailored for the local conditions 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 should be considered by operators in developing their individualized risk control program.

4/5-8 The ANSI Z380 Gas Piping Technology Committee (GPTC) should develop guidance material in the ANSI Z380.1, American National Standard for Gas Transmission and Distribution Piping Systems (GPTC Guide) to assist operators in determining which practices and methods are most appropriate for use by operators in prioritizing threats to their systems, which risk control practices are most appropriate for use by operators in addressing threats to their systems and which performance measures are most appropriate for use by operators in evaluating their risk control program.

4/5-9 The Gas Piping Technology Committee (GPTC) should consider additional guidance in the specific code areas (see Task 4 and Task 5, below).

4/5-10 The American Society for Testing and Materials (ASTM) should consider the need to take action to enhance performance test protocols (for components, burst tests, etc.) for plastic fittings, to incorporate protocols for the evaluation of elastomer related issues (gasket & O rings) and to add requirements for permanent marking of pipe and appurtenances so that materials can be redressed in a proactive manner should indications of problems be identified.

4/5-11 Operators may need guidance materials to comply with a high-level, risk-based, flexible federal rule. Small operators may need more extensive guidance for compliance.
4/5-12 On-going research and development activities are important to develop new practices, procedures, techniques and equipment which may positively impact distribution integrity management.

6-1 National performance measures of distribution integrity management should include:

1. Incident data contained in the Form PHMSA 7100.1.
2. The status of the operator in complying with the required elements of the program in accordance with deadlines established by the regulation.
3. The amount and ratio of pipe that is not considered "state of the art," i.e., pipe of a type which operators today would not normally install today (e.g., cast iron, unprotected steel and polyvinyl chloride (PVC)).

6-2 Operator-specific performance measures are unique and must match the specific risk control practices of its distribution integrity program as they are designed to address the threats to that system.
6-3 There is a lack on consensus as to whether measuring leakage, at a national level, is an appropriate measure of distribution integrity management.

7-1 The review of the operator's written distribution integrity management program should be at intervals not exceeding 15 months, but at least once each calendar year (the same interval currently required for review and update of its Operations and Maintenance (O&M) Plan (49 CFR 192.605)).
7-2 The operator should complete an evaluation of the effectiveness of its distribution integrity management program periodically. The period for the evaluation of program effectiveness should be specific in the plan and should be as frequent as needed to assure distribution system integrity.

Work Group Tasks

The work was organized into seven major tasks, based on the Report to Congress[30], which are discussed in detail:

1 Identify Threats
2 Identify Need For And Ways To Prioritize Threats
3 Identify Risk Control Techniques And Practices, Including Excess Flow Valves
4 Identify Current Federal Regulations, Identify Enhancement Needs, Identify Reference Standards Needs
5 Provide Suggestions To Address Enhancements In Regulations And References
6 Identify Performance Measures

[30] "Assuring the Integrity of Gas Distribution Pipeline Systems," Report to the Congress, May 2005, Submitted by Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, p. 24.

7 Provide for Periodic Evaluation Of Distribution Integrity Management Plans

Task 1 - Identify threats

Threat Categories

There are certain specific failure mechanisms that can occur to distribution lines. These mechanisms are referred to as threats. A variety of threats could be used. However, eight threats are identified in the PHMSA Annual Distribution Report, PHMSA Form 7100.1-1 as "Cause of Leaks" in Part C. These seem an appropriate set of threats for distribution operators.

The use of these categories may help to coordinate national distribution integrity management efforts with the reporting system currently in place. It is important to consider that the intent is to establish eight general categories of threats to review for risk control. These eight categories may need to be further broken down by the operator in order to fully address the threats.

Findings

1-1 A distribution integrity management program should consider the threats identified in the Pipeline and Hazardous Materials Safety Administration (PHMSA) Annual Distribution Report, PHMSA Form 7100.1-1 as "Cause of Leaks" in Part C:

1	Corrosion	5	Material or welds (Construction)
2	Natural Forces	6	Equipment
3	Excavation	7	Operations
4	Other Outside Force	8	Other

Task 2 - Identify Need For and Ways to Prioritize Threats

General

The eight threats listed above constitute the potential threats to any distribution system. However, each of the eight threats is not necessarily applicable to each operator's system. The threats that may exist may be adequately addressed by existing minimum federal safety standards (49 CFR 192), existing State regulations, orders or requirements, or by company practices.

To the extent that a threat is significant, it may be prevalent throughout the operator's system or it may exist only in certain specific sections of the system.

Characterizing Distribution Systems

An operator must begin by reviewing the data that characterizes its unique distribution system as the initial step in identifying threats and assessing and prioritizing the threats. An operator must have knowledge of its natural gas distribution system including: location, material composition, piping sizes, joining methods, construction methods, date of installation, soil conditions (where appropriate), operating and design pressures, history, operating experience performance data, condition of system, and any other characteristics noted by the operator as important to understanding its system. This information may be obtained from sources including system maps, construction records, work management system(s), geographic information system(s), corrosion records, operating and maintenance records and personnel who have knowledge of the system.

Each operator must have a certain level of knowledge about the distribution system for the operator to have an understanding of its system. It is not intended to require new analyses or inspections to acquire knowledge about the distribution system except where there is insufficient data for an operator to adequately evaluate system integrity. Current requirements for record keeping should have provided each operator with a substantial system database, particularly with respect to pipe installed after the adoption of 49 CFR 192. Where documentation is lacking, it may be possible for the operator to use the best information available to make realistic assumptions. It is often possible to operate a distribution system in a prudent fashion even without certain documented information.

Some process to divide distribution systems into logical distribution segments may be used, unless the system is so uniform that segmentation would be irrelevant. No single characterization process is adequate because distribution systems are so diverse. At a minimum, it is suggested that the process use material type, operating environment including geographic location, operating pressure, or pipe condition. Many operators have a system in place to characterize their systems. The integrity management framework should allow the operators to use their existing system where it adequately provides for an effective integrity management program. The number and size of distribution segments must be determined by the operator based on the conditions that exist and its program for effectively managing the risks of those distribution segments. The number of distribution segments is not necessarily a measure of the effectiveness of an integrity management program. A uniform national characterization process would not recognize the differing conditions under which distribution systems operate.

Vehicle Damage and Other Outside Force Damage

In analyzing Other Outside Force damages, it is important to note:

> “Vehicle-related incidents accounted for 67 of the 634 incidents or 11%. These incidents typically involve an automobile crash and a fire. Some involve a DUI, and some a rollaway vehicle, a riding lawnmower, or snow

> plow. One even involved a railroad incident. In the majority of cases, the Meter Set Assembly is damaged (44 or 66%)."[31]

And that:

> "Other Outside Force Damage causes the highest share of incidents involving a fatality – 40%. Vehicle-related incidents alone, a subset of Other Outside Force Damage, account for 25% of the incidents involving a fatality."[32]

While this threat is of great concern, there is insufficient breakdown of the data to fully identify its nature. The data set does not:

a) Identify where the facilities were located (e.g., at the property line or at the premises);
b) Indicate if any form of vehicle protection was present, and if so, the nature of the protection;
c) Identify the facility damaged (e.g., meter set, above ground regulator station);
d) Indicate if the cause of the fatality was related to the gas facility or independent of the gas facility (e.g., a person died from a heart attack and hit a gas facility when they lost control);
e) Indicate if drugs or alcohol were a factor in vehicle-related incidents; and
f) Indicate if the gas facility that was involved was near an area where vehicles would be expected or far off the traveled portion of a road or driveway.

The risk control practices used to address these incidents would vary based on the root cause of the incident. In some cases the practices have nothing to do with gas system design, construction, operation and maintenance. In others, there may have been adequate practices, but the nature of the incident was such that reasonable precautions could not solve the problem (e.g., a tractor-trailer combination may be so heavy and traveling at such a high rate of speed that it is not reasonable for the gas facility to be able to withstand such an impact). Further, a protection system sufficient to protect against large vehicles might make impacts by other vehicles deadly to the driver.

Therefore, this is an area where data collection needs to be improved so that the threat can be more clearly defined, and appropriate risk control practices implemented.

High Consequence Areas and Identified Sites

The concept of high consequence areas (HCAs) and Identified Sites was developed to address integrity management issue for liquid and gas transmission pipeline systems. Since a large portion of these pipelines traverse areas with little or no public presence, it was used as a way to identify those portions of the pipeline systems where the presence of the public was greater or more likely to be impacted by a pipeline failure.

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[31] Allegro Energy Consulting, "Safety Incidents on Natural Gas Distribution Systems: Understanding the Hazards," April 2005, p. 23.

[32] Ibid., p. 30.

Distribution systems are traditionally located near people. Since the entire distribution will be covered by the proposed distribution integrity management plan, there is no need to identify high consequence areas or identified sites.

Determining Applicable Threats to the System

After characterizing its system, the operator needs to identify which threats are relevant to the different distribution segments. The threat identification does not necessarily have to be sophisticated, but the process must meet the need of establishing a realistic identification of the threats, and a determination of whether their frequency and level of significance require a response that goes beyond normal operating practices.

Prioritizing Threats to the System

Once threats have been identified, the operator needs to develop a method to assess and prioritize the associated risks in order to address, first, those of greatest concern. In performing a risk analysis, it is important to note that risk is the mathematical product of the likelihood of an event occurring times the consequence of that event. An event that is highly likely and also has a high public safety consequence constitutes an event of greatest concern. An unlikely event having minimal consequence may not justify extraordinary precautions. Distribution incidents, (as defined in 49 CFR 191, Transportation of Natural and Other Gas By Pipeline: Annual Reports, Incident Reports, and Safety-Related Condition Reports, and contained in the PHMSA incident data base) often are events that are of low likelihood but of high consequence.

An operator should use a tiered approach to prioritizing risks based upon both the likelihood and consequence. If the likelihood is very low, a brief review of the consequences may be adequate (e.g., system pressure, proximity to business districts and the presence of EFVs). Similarly, if the probable consequence is low, it may not be necessary to dedicate significant effort unless the likelihood is very high. A tiered approach to risk prioritization can effectively focus resources to those areas where the risk is the greatest.

Risk can be reduced by implementing risk control practices (see Task 3) that decrease the likelihood of the event occurring, or mitigate the consequence of the event. In considering gas distribution systems, it is essential to remember that the consequences of a failure in a distribution system may take a protracted period of time to develop. During this period of time, certain techniques can be used to detect the failure and actions can be taken to address the failure before it produces an incident. This is why very few distribution leaks, which are routinely detected by the public and gas distribution operators; result in an incident. They are mitigated by effective leak management programs prior to incidents occurring.

The design and operation of distributions systems is so diverse that no single risk control method is appropriate in all cases. Many operators successfully use subject matter experts competent to make risk decisions. Some operators use risk prioritization programs that are data intensive, highly sophisticated, complex models. Other operators have developed models that use a few factors, but the most significant ones to their system, in a more simplified analysis that also produces the desired result. (One basis for deciding the validity of the risk analysis is to compare the predictions to the actual occurrences.)

In any risk analysis, it is necessary to identify the portion of the system or distribution segment that will be considered in performing the analysis. The distribution segment could be one-block long, a square block, or a larger segment such as an entire subsystem. What is essential is that the significant variables are the same for the entire distribution segment. What is necessary is that a valid analysis be performed that is consistent with the needs and the nature of the operations normally performed.

References

Some reference sources that address risk analyses and the prioritization of risks are listed in Exhibit B – Task 2 Report - Identify Need for and Ways to Prioritize Threats.

Findings

2-1 The distribution system characteristics must be identified.
2-2 The threats applicable to the system must be determined.
2-3 There is insufficient data regarding vehicle damage to gas facilities and other outside forces affecting gas facilities to develop a coherent understanding of the nature of the problem, and therefore, it is not possible to develop strategies to address this issue. It is an area where additional data needs to be developed.
2-4 The threats applicable to the system must be prioritized using risk control principals where risk = likelihood * consequence.
2-5 Operators may need guidance on how to characterize their system, identify the threats and to prioritize the threats.
2-6 Since the entire distribution will be covered by the proposed distribution integrity management plan, there is no need to identify high consequence areas or identified sites.

Task 3 - Identify Risk Control Techniques and Practices, Including Excess Flow Valves

General

Once the risk analysis is performed, it is necessary to have a series of techniques and practices that can be used to control the identified threat(s). The goal should be to give priority to those risks that pose the greatest hazard to public safety. The risk control techniques and practices can take the form of performing operation and maintenance activities as required by the existing regulations or performing those activities at more frequent intervals than otherwise required. The techniques and practices may also be performing other activities not addressed in the regulations, such as those contained in *the GPTC Guide. The risk control technique could be replacement of the facilities based on the risk analysis.*

Risk control practices and techniques vary. They may address the likelihood of a failure by monitoring and controlling the integrity of the distribution system. They may also address the consequence of a failure by dealing with response to preliminary indications of failures where actions by the operator may be able to prevent an incident. Further, they may address emergency response action which could mitigate the consequences of a failure or an incident.

The most frequently used risk control practice is leakage surveys. Federal regulation 49 CFR 192.703 requires that "[H]azardous leaks must be repaired promptly." Therefore, operators must at least classify those leaks they determine to be "hazardous" to comply with the regulation. However, there is no regulatory or universally-accepted definition of that term. Some people believe that a uniform system of classifying leaks would be appropriate. This might allow for consistent data on the frequency of hazardous leaks that could be used to evaluate the risk posed by leaks. Others believe that clarifying the instructions to the annual distribution report (PHMSA Form 7100.1-1) would be more effective to evaluate the impact on public safety. Still others believe that leak data is not a valid parameter for measuring distribution integrity management on a nationwide basis, though it is valuable in evaluating the effect of risk control practices of an individual distribution system.

An effective operator leak management program is an important risk control practice. The basic elements are enumerated in the findings below (the details of which are contained in Exhibit C - Effective Distribution Leak Management Framework).

Exhibit D - Task 3 Report - Identify Risk Control Techniques and Practices, Including Excess Flow Valves - contains a number of typical risk control practices used in distribution systems, identifies the threats each practice addresses and summarizes how the listed practice helps to mitigate the threat being addressed. This is a review of practices and an operator should choose those practices that meet the needs of its system based on its own risk analysis.

Operators should consider Excess Flow Valves (EFVs) as a risk control practice. The operator should document the factors to be considered in making a decision whether to install EFVs to address the excavation damage threat, or other threats due to natural forces or other outside force damage. Each operator should consider whether there are any specific circumstances that exist in its system that would render the EFVs ineffective. (Such circumstances include inadequate pressure to cause the EFV to activate, insufficient excess capacity in the service line such that there is an inadequate difference between the failure flow rate and the flow rate necessary to meet the load of the customer, or the presence of certain amounts of liquids and debris in the gas stream).

Findings

3-1 Risk control practices exist that can be used to address the integrity of distribution systems.

3-2 One risk control practice is an effective leak management program, the essentials elements of which are:

11) ***L*ocate** the leak,
12) ***E*valuate** its severity,
13) ***A*ct** appropriately to mitigate the leak,
14) ***K*eep** records, and
15) ***S*elf-assess** to determine if additional actions are necessary to keep the system safe.

3-3 Operators may need guidance on the application of available risk control practices to their systems.

3-4 Operators should consider the use of excess flow valves (EFVs) as a risk control practice to be used where appropriate.

Task 4 - Identify Current Federal Regulations, Identify Enhancement Needs, Identify Reference Standards Needs
&
Task 5 Provide Suggestions to Address Enhancements in Regulations and References

General

Tasks 4 and Task 5 were created as separate tasks. However, in processing these two tasks, it became clear that they are so interrelated that the most effective way to address these tasks was to integrate them and deal with them as a unit.

Using the identified threats listed in Task 1, federal and State regulations were evaluated to determine whether regulatory sections addressed each threat, whether reference standard requirements and guidelines addressed these threats, and identified enhancements to both regulations and guidance.

When many of today's older distribution lines were installed, the state-of-the-art in material science and joining was much less sophisticated than it is today. With modern materials, joining methods and construction techniques (for example, coated, cathodically protected steel joined by welding and/or pull-out resistant couplings and modern plastic joined by heat fusion), successful integrity management begins at the time of design and proceeds through construction and initial testing.

Findings based on a review of 49 CFR 192

A review of the Minimum Federal Safety Standards, 49 CFR 192,[33] [34] has resulted in the following findings:

4/5-1 Current design, construction, installation and initial testing regulations should be effective in providing for integrity of the distribution facilities that are being installed today,

4/5-2 Current operating and maintenance sections (including Subpart I) should be effective in providing the elements necessary to maintain the integrity on distribution lines,

4/5-3 Part 192, specifically §192.605 and 192.613, does not convey the concept of a risk-based distribution integrity management process that includes gathering system knowledge (surveillance), identifying trends, analyzing and prioritizing integrity threats and controlling the integrity related risks by prevention, detection and mitigation activities.

4/5-4 Part 192 needs a regulation that specifically requires a distribution integrity management program that includes the following elements:

1 The operator develop a written program plan that describes how it manages the integrity of its distribution system and focusing on how it will satisfy the requirements below. As operators develop formal integrity management programs, they will be guided both by federal and state requirements, as well as by their own analysis of their systems.

2 The operator identify threats applicable to its system.

3 The operator characterize the relative significance of applicable threats to its piping system.

4 The operator identify and implement appropriate risk control practices (or modify current risk control practices) to prevent, and mitigate the risk from applicable threats consistent with the significance of these threats.

5 The operator develop and monitor performance measures to allow it to evaluate the effectiveness of programs implemented.

6 The operator periodically evaluate the effectiveness of its program and make adjustments dictated by its evaluation.

7 The operator periodically report to the jurisdictional regulatory authority a select set of performance measures.

4/5-5 Part 192 has some areas where minor changes would result in some improvements related to distribution integrity management issues:

1 Portions of the Guide Material in ANSI/GPTC Z380.1 Guide for Gas Transmission and Distribution Piping Systems could be referenced in 49 CFR Part 192.7 for certain code sections as a resource to the Operator.

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[33] Each of the Subparts and Appendices to 49 CFR 192 were reviewed.

[34] The Operations threat has largely been addressed by the recent regulations promulgated by the Office of Pipeline Safety entitled Qualification of Pipeline Personnel (49 CFR 192 Subpart N), commonly referred to as OQ (Operator Qualification). It is important to note that the requirements in Subpart N are relatively new (effective August 26, 1999, with employees being required to be qualified by October 28, 2002). As industry gains experience with these requirements, it can be determined whether the goal of reducing incidents due to operator error has indeed been accomplished.

2 Language should be added to 192.755 addressing the option of replacement as an alternative to protecting undermined cast iron pipe.

3 Add a requirement for written construction standards for service lines in 192.361, similar to the requirement for written construction standard for mains and transmission lines in 192.303.

4 192.723 Distribution systems: leakage surveys - RCP group determined there is an issue with the code requirement needing to include verbiage requiring "*appropriate*" leak detection equipment.

5 Changes may be necessary to 192.614 – Excavation damage. Action in this area was referred to the Excavation Damage Work Group.

6 The SIRRC II (State Industry Regulatory Review Committee) efforts to clarify code requirements in Subparts J, K and L could:

- a Eliminate confusing, ambiguous, and conflicting language,
- b Clarify the distinction of the sections and paragraphs applicable to transmission and those applicable to distribution,
- c Ensure code requirements for uprating and establishing the MAOP of distribution systems are clarified as a distinct set of rules,
- d Simplify and facilitate compliance with rule provisions while ensuring safety is maintained or enhanced,
- e Eliminate confusing cross-references.

State Requirements

A review of a survey of State regulations exceeding Part 192 requirements resulted in the following findings:

4/5-6 Some of States have requirements or programs related to distribution integrity management that exceed those of Part 192 and cover the following areas:

- a Pipe Replacement - Mains
- b Pipe Replacement – Services and Appurtenances
- c Leak Management including leak response time and backlogs of scheduled leak repairs
- d Damage Prevention
- e Corrosion Control

4/5-7 State requirements or programs exceeding Part 192 are often tailored for the local conditions 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 should be considered by operators in developing their individualized risk control program.

Industry Standards

While the regulations incorporate many of the key elements that would need to be included in a distribution integrity management program, it is anticipated that a new, high-level requirement will be imposed for a distribution integrity management program, creating a need for additional instruction and guidance. Many distribution operators use the Gas Piping Technology Committee (GPTC) ANSI Z380.1 Guide for Gas Transmission and Distribution Piping Systems (GPTC Guide) for guidance material and that is efforts were concentrated in that area. A review of the GPTC Guide has resulted in the following findings:

> 4/5-8 The Gas Piping Technology Committee should develop guidance material to assist operators in determining which practices and methods are most appropriate for use by operators in prioritizing threats to their systems, which risk control practices are most appropriate for use by operators in addressing threats to their systems and which performance measures are most appropriate for use by operators in evaluating their risk control program.
>
> 4/5-9 The Gas Piping Technology Committee should consider additional guidance in the following areas:
>
> 1 192.317(a) and (b) - Protection from hazards, vehicles, frost, drought, and heat conditions- GPTC has guide material (one paragraph under item 7 of an appendix) regarding vehicular traffic for above ground structures, however, this material is "buried" in a referenced appendix (G-192-13) included in the guide material for this section. This material could be re-formatted to highlight guidance to prevent vehicular damage to the main, as well as meter and service regulator installation. GPTC guide material also needs to be developed to specifically address effects due to frost, drought and heat.
>
> 2 192.325 - Underground clearance – GPTC has guidance, but does not specify minimum clearance. Additional guide material needed.
>
> 3 192.353 and 192.355 – Meter and regulator protection from damage – GPTC guide material needs to be updated to better address the threat from vehicular damage, especially in light of the analysis of incidents from vehicular damage to meter and regulator sets. (See final rule for a detailed discussion on this threat – Docket RSPA-02-13208, and Amendment 192-93).
>
> 4 192.361 – Service lines installation - GPTC consider including guidance addressing what should be desirable clearances where practical.
>
> 5 192.365 – GPTC guide material is needed for location of service line valves. Valves should be outside structures where practical for high pressure and large services. GPTC should consider a recommendation to install valves outside when the size of line is greater than 2", the service is high pressure or the service is to a public building.
>
> 6 192.465 (e) - External corrosion control – GPTC guide material is needed to address the time frame within which protection must be accomplished in areas of active corrosion.
>
> 7 192.557 - Uprating cast iron pipelines – GPTC provides guide material in its Appendix G-192-18 for cast iron pipe, which identifies conditions where cast iron may be susceptible to failure, and or need protection. Effectiveness of "protection" when cast iron pipe is being impacted still needs further guidance. Even though a less than state of the

art material, cast iron still may have its pressure uprated. Standards identified by GPTC guidance for cast iron design ANSI/AWWA (American Water Works Association) C101-67 was withdrawn in 1982, and another reference to cast iron pipe, ASTM A377, was removed from Part 192 Appendix B, "Qualification of Pipe," by amendment 192-62 in 1989. GPTC guidance is needed when an operator consider uprating cast iron pipe.

8 192.617 - Investigation of failures - This section covers root cause analysis of leaks, failures, incidents and requirements for corrective and preventive actions stemming from that analysis. The GPTC guide material explains it applies to leaks and failures, however some operators only apply the process to reportable incidents and the guide material uses the term incident. The guide material references especially for approaches to root cause analyses, need to be updated, and the guide material revised to better reflect incident as well as leak and other failure investigations and analyses.

9 192.707 – Line Markers - GPTC Guide Material Appendix G-192-13 lists examples of locations for placement of line markers; further guidance on spacing to address "close as practical" should be developed to address change of direction and line of sight considerations.

10 192.723 - Distribution systems: Leakage surveys – GPTC Guide material on limitations/sensitivities of leak detection equipment is needed.

11 192.727 – Abandonment or inactivation of facilities – Part 192 does not address handling of inactive service lines (for example duration, maintenance). GPTC guidance material is recommended to address the tracking, maintenance and duration of inactive service lines.

4/5-10 The American Society for Testing and Materials (ASTM) should consider the need to take action to enhance performance test protocols (for components, burst tests, etc.) for plastic fittings, to incorporate protocols for the evaluation of elastomer related issues (gasket & O rings) and to add requirements for permanent marking of pipe and appurtenances so that materials can be redressed in a proactive manner should indications of problems be identified.

Small Operators

Small operators may need more detailed assistance than is currently found in the GPTC Guide. Whether this can be provided by GPTC or through some other vehicle (such as a small operators' guide), further guidance is needed to assure distribution integrity for all operators. PHMSA needs to address how guidance material will be addressed, whether by including references in 49 CFR 192.7, through incorporation by reference, or by some other means.

4/5-11 Operators may need guidance materials to comply with a high-level, risk-based, flexible federal rule. Small operators may need more extensive guidance for compliance.

Research and Development (R&D)

A detailed summary of Research and Development (R&D) activities applicable to enhancing distribution safety is contained in Exhibit E. A review was performed to look at what may be able to be accomplished in the R&D area to further improve the industry's capabilities to address safety integrity needs. A summary of R&D activities impacting distribution systems are:

1. Excavation Damage
   - Improved capability of pipe locating devices, (including plastic), alignment and depth, as well as features on pipe.
   - Backhoe and boring sensor technology to prevent damage to underground facilities
2. Leak Management
   - Improved leak investigation and pinpointing equipment capabilities, including leak detection to provide different approaches and thinking for applying risk control practice tools such as inspections, patrols and surveys
3. Data Gathering, Analysis and Integration
   - Improved process for easier and less costly GIS implementation
   - Improved failure prediction tools and methodologies, (including repair vs. replace guidance logic)
   - Improved data collection methods, as well as data integration
   - Improved real time sensing of conditions on the pipeline system
4. Other Mitigation Improvements
   - Methods to reduce corrosion rate on unprotected pipe
   - Improved coating repair and repair system

4/5-12 On-going research and development activities are important to develop new practices, procedures, techniques and equipment which may positively impact distribution integrity management.

Task 6 - Identify Performance Measures

General

As is the case whenever one wishes to compare past, present and future conditions, it is necessary to have a means to objectively measure the difference of some variable over the periods. In the case of distribution line integrity, it will be necessary to establish performance measures by which to gauge an individual operator's performance, as well as the performance of the industry as a whole.

National Performance Measures

1 Incident Data

Gas distribution safety, on a national basis, is generally viewed in terms of the number of incidents, fatalities, injuries and property damage occurring over a given period of time. While any incident is an event to be avoided, the number of incidents that occur in gas distribution lines is small. Thus, the data available for analysis is often so limited as to preclude statistically valid conclusions. Since the key issue is that of public safety, incidents and the consequent fatalities and injuries will continue to be the most important measures of performance. However, because this measure has limitations, additional national performance measures will need to be reviewed.

With the implementation of a distribution integrity management regulation, an appropriate measure would be the status of the operator in complying with the required elements of the program in accordance with deadlines established by the regulation.

2 Pipe Inventory

Also, a valid national performance measure may be to monitor the amount and ratio of different pipe types in service. Pipe types that operators normally install today (e.g., coated and cathodically protected steel and polyethylene plastic pipe) are considered "state-of-the-art." The term is not meant to imply that other pipe types are inherently unsafe. With proper maintenance and care these other "not state-of-the-art" pipelines may remain capable of operating safely for many years. However, there have been instances where such pipe was not performing well. Many operators have active programs to replace this pipe, and there have also been instances where States have encouraged, or required, operators to renew their distribution systems by phasing out their higher risk pipe. For these and other reasons, nationally significant amounts of pipe that are not "state-of-the-art" are replaced or retired annually.

3 Leakage Data

There is a lack on consensus as to whether measuring leakage, at a national level, is an appropriate measure of distribution integrity management. A brief description of the options is outlined below, while a more complete discussion is contained in Exhibit F.

Some believe that it is a valid measure because all incidents come from leaks; the public may equate leaks with integrity and existing leakage data while not perfect should present a reasonable way to measure the performance.

Others believe that it is not a valid measure because the vast majority of leaks are discovered through routine operations and are repaired or eliminated without threat to the public by effective leak management programs; most leaks are not hazardous and therefore leak numbers are not an indicator of risk or threat to the public; there is no way to determine which leaks will become safety problems; existing leak data is not uniform and may cause distortions; the number of leaks eliminated by pipeline replacement is not consistently reported by operators; an increase in leaks repaired or eliminated, whether all leaks or only hazardous leaks, could raise concern that gas system integrity is decreasing, but it may mean operators are more aggressively finding and responding to leaks – it may actually be a positive safety indicator. Data related to the cause of incidents is not consistent with the data related to the cause of leaks.

All agree that leak data would be a better indicator of risk if the number of potentially hazardous leaks were reported, instead of numbers that include all leaks whether they posed a hazard to the public or not. Reporting hazardous leaks separately would impose a new reporting requirement and would require regulatory imposition of a national leak classification system, which some operators consider costly and not necessarily beneficial.

4 Other

A variety of other potential national performance measures were reviewed (such as age of pipe, unaccounted-for gas, safety-related condition reports - see Exhibit F Task 6 Report - Identify Performance Measures). It was determined that none of them would be appropriate national performance measures.

Operator Specific Performance Measures

In the case of an operator, or the operation of a particular system, the incident data will contain insufficient information from which statistically valid analyses can be made, and other measures will have to be used. Therefore, the operator must establish a baseline and develop and monitor performance measures to evaluate the effectiveness of its program. The operator must re-evaluate threats and risks as appropriate. Since the company-specific performance measures are directly related to the individual company situations and local conditions, a federal regulatory requirement dictating the use of specified performance measures is not practicable. Using individual company data to compare individual operator programs or evaluate the performance of the industry on a state or national basis would not be appropriate.

Each operator must evaluate its system and determine which threats are applicable to that system. Each operator should develop performance measures that match the specific risk control practices of its distribution integrity program. Performance measures should reflect the purpose of the distribution integrity program or specific risk control practice. Performance measures should be something that can be counted, graphed and validated. It is best to select "a critical few" measurements. There are often decreasing returns as measurements are added, and too many measurements can overwhelm the measurement system.

Measures developed may be unique to each operator. Measures may be gathered and tracked for an entire system, specific geographic areas, material type, or other reasonable categorization.

Exhibit F Task 6 Report - Identify Performance Measures contains some examples of performance measures that may be appropriate for an operator to employ to address program effectiveness.

Findings

6-1 National Performance measures of distribution integrity management should include:

1. Incident data.
2. The status of the operator in complying with the required elements of the program in accordance with deadlines established by the regulation.
3. The amount and ratio of pipe that is not considered “state of the art,” i.e., pipe of a type which operators today would not normally install today (e.g., cast iron, unprotected steel and PVC).

6-2 Operator-specific performance measures are unique and must match the specific risk control practices of its distribution integrity program as they are designed to address the threats to that system.

6-3 There is a lack on consensus as to whether measuring leakage, at a national level, is an appropriate measure of distribution integrity management.

Task 7 - Provide for Periodic Evaluation of Distribution Integrity Management Plans

General

Periodic evaluation of a program is an integral part of any continuous improvement process, including the distribution integrity management program of an operator. Program evaluation is performed to confirm that the essential elements of the process are identified, implemented and effective. In addition, threats and their priorities may change over time as conditions change or as mitigation projects are completed.

An operator must “review and update (sic)” its Operations and Maintenance (O&M) Plan “at intervals not exceeding 15 months, but at least once each calendar year” (49 CFR 192.605). This interval should be an appropriate one for the operator to use in reviewing its written distribution integrity management plan.

Additionally, the operator should complete an evaluation of its distribution integrity management program periodically to monitor its effectiveness in assessing distribution integrity and addressing identified threats. The period for the evaluation of program effectiveness should be as frequent as needed to assure distribution system integrity. This review period should be determined by the operator and included in its written integrity management program. The time frame for review of individual internal performance measures may be different. The annual review of the written integrity management program will include a review of the appropriateness of these operator established intervals. Meaningful data may be available to support an annual review; however, requirements related to the frequency of evaluation should provide the flexibility to accommodate a wide range of risk control practices and the measures used to evaluate them. Practices such as public education programs, for example, may take several years before meaningful data trends can be established. Some factors to consider when determining the frequency of evaluation include: the nature and significance of the threats, the complexity and extent of the risk control practices, the frequency of performance measurements and the quality of data related to those performance measures.

The evaluation of program effectiveness should include the following items to determine if modifications to the program need to be made:

- Risk prioritization results
- Risk control practices
- Failure analysis results
- Performance measures

The method of evaluation could range from a formal audit of the program to a simple review of the above items by a subject matter expert, based on the needs of the program.

Findings

7-1 The review of the operator's written distribution integrity management program should be at intervals not exceeding 15 months, but at least once each calendar year (the same interval currently required for review and update of its Operations and Maintenance (O&M) Plan (49 CFR 192.605)).

7-2 The operator should complete an evaluation of the effectiveness of its distribution integrity management program periodically. The period for the evaluation of program effectiveness should be specific in the plan and should be as frequent as needed to assure distribution system integrity.

CONCLUSION

Some gas distribution systems have physical properties and other operating parameters, such as some distribution systems, designed, constructed, operated and maintained under existing federal and state regulations, as well as industry and individual operator practices, that produce extremely high levels of distribution integrity (other than exposure to excavation damage). These systems represent a minimal threat to public safety. While it is essential that they be monitored to identify any problem that might develop, extensive resources need not be expended on these facilities.

On the other hand, certain facilities, because of the interaction of factors such as material with which they are constructed, the means used to install them, and unfavorable environmental conditions, have a greater likelihood of developing integrity issues. The consequence of an incident can vary dramatically based on local parameters. It is in this collection of facilities that significant resources may need to be expended to define, evaluate and mitigate risks.

A set of threats applicable to distribution systems has been identified. Techniques exist for an operator to prioritize the threats, to perform a risk analysis, and to identify and implement appropriate risk control practices to address the integrity of its systems.

Appropriate performance measures can be developed that an operator can choose to monitor as a means to evaluate its program.

There are no major areas of 49 CFR 192 that need to be changed to address distribution integrity management, with the exception of a high-level, risk-based, flexible performance regulation to require a written distribution integrity management plan by the operator, although some incidental revisions may be needed to avoid duplication or conflict. The requirement should be for a broad framework of risk-based actions to address those areas where the risk to public safety is the highest. There is a need for additional guidance materials to assist some operators in developing their integrity management programs.

Continuing research and development activities are needed to attempt to improve industry's capability to address integrity issues. Also, industry needs to continue to explore innovative approaches that may result in integrity improvements to their systems. These approaches should be shared with all operators.

State pipeline safety agencies are required to evaluate the process. Collaborative efforts by States and operators can produce synergies in the development of effective integrity management programs that are in the pubic interest. Cost effective distribution integrity management should produce improved levels of safety for the public at a reasonable cost.

Exhibit A

Distribution Integrity Management – Risk Control Practices Group

Member	Organization
John Frantz	PECO Energy (Gas Piping Technology Committee)
Bruce Hansen	Office of Pipeline Safety
John Jolly	Philadelphia Gas Works
George Miller	NJ State Fire Marshal (ret.) (National Assn. of State Fire Marshals)
Gavin Nicoletta	New York State Public Service Commission (NARUC)
Lee Reynolds	NiSource
Jerry Schmitz	Southwest Gas Corp.
Philip Sher (Chair)	Connecticut Dept. of Public Utility Control (NAPSR)
Darrin Gordon	City of Safford, AZ
Don Stursma	Iowa Utilities Board (NAPSR)
Participant	Organization
Glen Armstrong	EN Engineering (Gas Piping Technology Committee)
Philip Bennett	American Gas Association
DeWitt Burdeaux	Office of Pipeline Safety
George Mosinskis	American Gas Association
Support	Organization
John Gawronski	Cycla Corporation

Exhibit B

Task 2 Report - Identify Need for and Ways to Prioritize Threats

I Introduction

The operator needs to identify those threats, which based upon system characteristics, render specific portions of its system susceptible to that threat. The operator must then determine the likelihood of the threat affecting its system. Finally, the consequences to susceptible portions of the distribution line environment in the event that a threat causes a failure, need to be estimated. The significance of the combination of the threat(s) to which an operator's system is most vulnerable and the effect on the distribution line's surroundings will help the operator establish risk priorities to be addressed.

II Documentation of Data on the Physical Characteristics of Distribution Lines and the Environment in Which They Reside That Would Be Useful To an Operator in Characterizing and Managing System Risk

Characterizing a distribution system into logical units facilitates the process of prioritizing risks. The distribution system should be divided into a sufficient number of distribution segments in order to effectively address the needs of the system. An operator can manage risks by addressing significant threats to the distribution segments.

In evaluating their gas system, operators may arrange their data so that vulnerability to failure may be more easily identified, such as by type of pipe material, type of component and location. This information, integrated with root causes of failures, corrosion and operating history and other factors associated with the distribution pipe, may help the operator identify the threats affecting its gas system.

Risk prioritization may require that the operator identify specific physical characteristic factors affecting the susceptibility of distribution components to a threat as well as factors associated with the environment nearby the distribution line that can affect the consequence of a leak or failure. Operators may choose to develop a list of factors specific to their operations or select from a general list those that address specific threats to which their system is susceptible. A general list might include such factors as:

1 *Environmental factors*
- a) frost impacts (in areas where frost line approaches the buried piping)
- b) geologic conditions
- c) soils liquefaction properties (in high seismic areas)
- d) construction activities (significance of near-by construction)
- e) anticipated natural forces (e.g. flooding and wash outs)
- f) types of soils

2 *Material factors*
- a) cast iron

b) wrought iron
c) bare steel
d) copper
e) various types of plastic
f) pipe diameter
g) wall thickness
h) manufacturing process

3 *Consequence factors*

a) operating pressure
b) population density (“downtown” versus rural)
c) impact of loss of supply
d) number of customers affected
e) proximity to structures and critical facilities (e.g. schools and hospitals)
f) proximity to known groups of people with limited mobility (usually institutionalized)

4 *Operations factors*

a) condition of material
b) leak rates - current and historic
c) cathodic protection history
d) cover depth (exposure to excavation damage)
e) presence of third party construction in area
f) farming area
g) age of facility

5 *Practical factors*

a) resource limitations
b) rate recovery allowed by rate regulator
c) state incentives (e.g. for replacement programs)
d) immediacy of the safety hazard

Operators may apply a subset of these factors or weigh selected factors based on the operating conditions and system materials. Evaluation of system data may aid in characterizing a distribution system into logical units such as material type, installation date, location, etc. Some examples include:

a) The history of leaks or failures by material - per mile, or per 1000 services of a particular material,
b) The manner in which the material fails - such as a pinhole, a crack, or a rupture,
c) The history of leaks or failures by decade of installation,
d) The history of failures within a geographic region,
e) Susceptibility to other threats - such as natural forces, corrosion, or excavation activities.

Consequence factors for consideration might involve identifying environment conditions where a particular pipe material is located such as:

a) Proximity to habitable structures,
b) Location beneath wall-to-wall paving,
c) Location in soils with water, or those with a corrosive nature,
d) Location where other subsurface conduits may enlarge gas migration patterns,

e) Locations susceptible to ground movement,
f) Proximity to sensitive types of buildings - such as schools, fire houses, etc.
g) Proximity to known groups of people with limited mobility (usually institutionalized)
h) Proximity to commercial centers or densely populated areas.

III DETERMINE WHEN AND WHERE APPROACHES AND PRACTICES SHOULD BE USED TO CHARACTERIZE THE RELATIVE SIGNIFICANCE OF APPLICABLE THREATS TO ALL SEGMENTS OF THE SYSTEM

By prioritizing the threats to its distribution system, an operator can identify the areas of highest risk. Risk is represented by the following equation:

Risk = likelihood of occurrence X consequences of a failure

> where likelihood is a measure of the possibility of an event occurring while the consequence is a measure of the effect on people. Protection of property is also important and may become more significant in areas where the concentration or proximity of people is insignificant.

Prioritization (i.e., characterization of the relative significance) of applicable threats to an operator's entire distribution system needs to be accomplished. Depending on the quality and extent of data available and the size and complexity of the distribution system, this could involve significant effort.

A tiered and staggered implementation approach over a period of time may be needed. No single characterization time frame is proposed here due to the diversity of distribution systems. Operators need to identify a process that works for them. Dividing distribution systems into logical units for characterization may be appropriate unless the system is so simple or uniform that identifying relevant factors is unnecessary. Such a process could be based on identified threats, population density, threat prioritization method employed, material type, geographic location, operating pressure, pipe condition, or homogeneity of the distribution system. Integrity management requirements should be flexible enough to allow operators that already have them to use their existing threat identification and risk assessment approaches where it adequately provides for an effective integrity management program.

Periodic review of each portion of the distribution system should be undertaken based on the results of evaluation of the performance measures the operator has established.

IV DETERMINE THE MEANS BY WHICH OPERATORS MAY CHARACTERIZE THE RELATIVE SIGNIFICANCE OF THREATS TO SEGMENTS OF THE SYSTEM

1 Data Sources for Identification and Prioritization of Threats

The Risk Control Practices (RCP) Work Group discussed and reviewed the following data sources for applicability to the identification and prioritization of threats to gas distribution piping. Operators may be able to find useful information in any one of them. Operators are encouraged to consult other sources of which they may have knowledge.

- (a) American Gas Association (AGA) – Benchmarking/Innovative Practices
- (b) AGA Gas Engineering and Operating Practices (GEOP) Series
- (c) Pipeline Risk Management Manual by W. Kent Muhlbauer
- (d) Gas Piping Technology Committee (GPTC) - American National Standards Institute (ANSI) Z380.1 Guide for Gas Transmission and Distribution Piping Systems
- (e) Gas Technology Institute (GTI) Publications - including predecessor organizations Gas Research Institute and Institute of Gas Technology
- (f) American Gas Foundation (AGF) Study - Safety Performance and Integrity of the Natural Gas Distribution Infrastructure January 2005
- (g) GPTC Technical Report - ANSI GPTC Z380 TR-1 Review of Integrity Management of Natural Gas Transmission Pipelines
- (h) American Society of Mechanical Engineers (ASME) Standard B31.8S - Managing System Integrity of Gas Pipelines
- (i) Transportation Safety Institute (TSI) website (www.tsi.dot.gov)
- (j) Regional Industry Organizations
  - (i) Midwest Energy Association (MEA)
  - (ii) Southern Gas Association (SGA)
  - (iii) Northeast Gas Association (NGA)
  - (iv) Western Energy Institute (WEI)
- (k) National Fire Protection Association (NFPA) - NFPA 54 National Fuel Gas Code
- (l) Canadian National Standard - CNS Z662-1999
- (m) Pipeline and Hazardous Materials Administration (PHMSA) Data Analysis
- (n) National Transportation Safety Board (NTSB) - pipeline accident reports
- (o) PHMSA Advisory Bulletins
- (p) Guidance Manual for Operators of Small Natural Gas Systems - PHMSA publication
- (q) Training Guide for Operators of Small LP Gas Systems - TSI publication
- (r) PHMSA website (ops.dot.gov) (ops.phmsa.gov) {Place holder - coming soon}

2 Methods for Identification and Prioritization of Threats

An operator must consider every identified potential threat to a distribution system in its prioritization effort. However, by using a tiered approach, and knowledge of its system, an operator can reasonably determine the most credible risks associated with its individual distribution system. These operator-determined credible risks should be subject to more rigorous scrutiny and application of risk control practices. The other less credible threats should be reviewed periodically and raised to a higher awareness level when they become more of a concern. This could occur due to changes in the system itself or the environment it operates in or by reducing or controlling an initially higher priority risk.

The following methods appear to be most promising for distribution system operator consideration:

(a) Subject Matter Expert (SME) Method

The operator should choose Subject Matter Experts (SMEs) who are knowledgeable about construction, operations, and maintenance activities and the operator's system characteristics. The individual SMEs may be employees, consultants or contractors, or any appropriate combination. The purpose of this group is to review the data gathered during routine operations and maintenance activities, special field surveys or patrols, as well as failure reports and analyses to develop a relative value for the likelihood of each threat. When combined with perceived or known consequences a relative risk can be assigned to each threat.

An SME team can perform in an informal setting and structure, or in a more rigid format. Procedures may be defined by the operator or a consultant to direct the SME deliberations and organize their conclusions.

(b) Mathematical Algorithm Methods

(i) Operator Developed Risk Ranking Programs

Some operators have developed in-house programs or processes for analyzing the condition of their distribution system which have proven effective over time. Those that give acceptable results can continue to be used as risk prioritization tools. The operator should review its program or process and consider modifications where necessary to ensure that all the requirements of a distribution integrity rule are incorporated. Additional data gathering and integration, analysis for particular risks specified and reporting may be needed.

(ii) Commercially Available Risk Ranking Programs

(A) TUBIS™/Optima - A Budget Planning and Risk Management System for Pipeline Networks - for Steel and Cast Iron[35]

TUBIS™ is a Windows NT based software package that is self-learning in that it can start with a minimal amount of data and then incorporate newly collected data to change its knowledge of the distribution system. It has separate modules for cast iron, bare steel and coated steel as well as optimization procedures addressing networks consisting of all these materials. The final result includes a defensible, prioritized list of segments to replace based on risk and economic issues as well as network objectives.

[35] Available from New York Gas Group, 1515 Broadway, 43rd Floor, New York, NY 10036, 212-354-4790 or Optima Inc., 55 Francisco Street, Suite 780, San Francisco, CA 94133-2122, 415-421-5800.

(B) Advantica Mains Replacement Prioritization (MRP) - for Steel and Cast Iron[36]

MRP is a strategic management tool that that assists in selecting the replacement strategy that will keep pace with the wear-out rate of the overall distribution piping network. MRP's field tested and defensible predictive features and its scenario evaluating Decision Support Tool combine to ensure you are meeting the needs of your network through just the right level of investment. MRP is a strategic geospatial tool that computes the present condition of metallic mains in terms of future leaks; calculates the risk of incidents posed by the aging metallic mains; predicts the rate of change in condition and risk over time; facilitates the development of replacement strategies based on criteria such as length, expenditure, material, age operating pressure or diameter; enables the assignment of a "replacement year" to each main; and allows the use of GIS tools to manage inputs and results in an open environment.

(C) Optimain Decision Support (DS)[37]

Optimain DS supports integration with all major GIS and relational database systems for access to and analysis of Leak, Main, Service, Building usage/density and other spatial or relational attributes. It provides system-wide distribution integrity assessment for the following types of pipes and programs: Cast Iron mains, Unprotected Steel Mains, Protected Mains, Plastic Mains, and CI, Steel, copper and Plastic Services. Optimain DS enables users to define discrete project "envelopes" based on various criteria including: default main configuration; leak concentrations, address ranges, or user defined spatial envelopes. Its "Pipe Analysis Wizard" can be used to auto-generate and monitor projects for an LDC's entire system, enabling system-wide assessment of projects and programs. Optimain DS uses numerous probabilistic algorithms to forecast pipe failure, determine risk consequence (risk profile), and provide risk and economic scores for each project, enabling system-wide comparison, ranking and analysis of all projects and programs. Its "Multi-Project Analyzer" provides automated refresh, recalculation and re-ranking of projects based on the latest leak, inspection and environmental information. Optimain DS goes well beyond the traditional "repair/replace" analysis, by using LDC specific business rules and algorithms that assess the cost and risk reduction potential of various risk mitigation alternatives including: increased surveillance, rehabilitation, repair, or replacement.

(D) PIMOS (Pipeline Inspection and Maintenance Optimization System) for Steel Systems[38]

PIMOS models five types of pipeline defects: external corrosion, internal corrosion, stress corrosion cracking, material/manufacturing defects, and mechanical damage (sustained and future). It should assist in making the most cost-effective decision regarding type and timing of inspection and maintenance on individual segments of gas transmission pipeline. Core models were developed from the pooled data of participating companies. Susceptibility factors and decision trees for the defects to be analyzed were developed, the actions defined in the decision trees were refined, and a revised data dictionary was produced. [Though still available, this program is not actively supported by GTI. For those operators that use it, its principles are still

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36 Available from Advantica- 1170 Harrisburg Pike, P.O. Box 86, Carlisle, PA 17013, 717-243-1900 or 5177 Richmond Avenue, Houston, TX 77056, 713-586-7000

37 Available from Vantage Management Solutions, Inc.; 28 South State Street; Newtown, PA 18940; 215-968-7790

38 Available from GTI, GRI-92/003 updated in 1995 as GRI-95/0181

applicable. Its primary drawback is that it was written in DOS and has not been updated to a Windows-type format.]

(E) CIMOS (Cast Iron Maintenance Optimization System) for Cast Iron Systems[39]

CIMOS was developed to respond to the need for a reliable method to identify failure-prone cast iron pipe segments and to evaluate priorities for proactive improvement actions including replacement and preventative maintenance. It takes into account the predicted frequency of leaks, repair versus replacement cost, and the probability and consequences of an incident following a leak. CIMOS consists of four interrelated analytical models, a database of inventory characteristics and leak repair histories, and a personal-computer based software system. The analytical models include a leak-prediction model, a break prediction model, a life-cycle costing model, and a priority assessment model. [Though still available, this program is not actively supported by GTI. For those operators that use it, its principles are still applicable. Its primary drawback is that it was written in DOS and has not been updated to a Windows-type format.]

V REFERENCES

1 GPTC Guide for Gas Transmission and Distribution Piping Systems ANSI/GPTC Z380.1-2003[40]

The guide material contains information and some "how to" methods to assist an operator in complying with 49 CFR Parts 191 and 192. The guide material is advisory in nature and must be applied in conjunction with sound judgment as to applicability to a particular gas system. The Guide contains numerous references helpful in addressing risk and threat prioritization although not in readily identifiable format. GPTC is preparing an appendix that will address all phases of distribution system integrity applications in addition to directing an operator to guide material specific to each identified threat.

2. Pipeline Risk Management Manual, W. Kent Muhlbauer[41]

The "Muhlbauer" manual provides a comprehensive background in the principles of pipeline risk modeling. It does not include a specific model but contains information and insight that will assist an operator in developing a system-specific risk determination method. A generic algorithm is suggested with advice on how to determine and assign appropriate weighing factors.

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39 Available from GTI, GRI-92/0243 updated in 1995
40 Available from American Gas Association, 400 North Capitol Street, NW, Washington, DC 20001, ANSI catalog number X60306
41 Available from Gulf Professional Publishing, 200 Wheeler Road, Burlington, MA 01803, ISBN: 0-7506-7579-9

Exhibit C

Effective Distribution Leak Management Framework

Leak management is an important risk control practice used by natural gas distribution operators to maintain the integrity of the nation's distribution system network. Operators consider many location and distribution system specific factors to evaluate the severity of the leak and determine the appropriate actions to take to mitigate the risk associated with the leak.

Although some elements of leak management have evolved with improvements in technology and the development of operation and maintenance codes and standards, distribution operators have used the same basic elements since the early days of the industry. An effective operator's leak management program has the following basic elements:

- ***L*****ocate** the leak,
- ***E*****valuate** its severity,
- ***A*****ct** appropriately to mitigate the leak,
- ***K*****eep** records, and
- ***S*****elf-assess** to determine if additional actions are necessary to keep the system safe.

Locate the leak
An effective leak management program starts with locating leaks by visual inspection, leak survey equipment, timely response to customer notification of a gas odor, and a variety of other means. It involves the use of qualified personnel to perform leak detection activities and the selection of appropriate leak detection equipment. Operators should have internal procedures that delineate the frequency and type of leak surveys to be conducted which are based on environmental conditions, the operator's knowledge of the distribution system, and regulatory requirements. It should be noted that operators are required to conduct routine leak surveys per 49 CFR Part 192.

Evaluate the severity of the leak
An effective leak management program includes evaluating the severity of a leak according to established classification criteria. These classification criteria take into consideration the safety risk posed by the leak. The determination of leak migration is part of the process.

Leaks could be classified using the following criteria:

- *Leaks that require immediate action (hazardous leaks)*: A leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.

- *Leaks scheduled for repair*: A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.
- *Monitored leaks*: A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.

Operators who have worked out separate classifications with their state regulators follow the state classifications.

***A**ct* appropriately to mitigate the leak

Once a leak has been located and evaluated, an operator takes actions that are consistent with the severity of the leak. This may include temporary or permanent repair, replacement, or other steps that reduce any immediate hazard posed by the leak. This may also include scheduling the line for repair or periodic monitoring in the case of non-hazardous leaks.

***K**eep* records

An effective leak management program includes the collection and recording of data pertinent to a leak to increase the operator's knowledge of the system, measure its performance and comply with regulatory reporting requirements.

***S**elf-assess*

An effective leak management program includes a self-assessment of the operator's distribution system by compiling associated performance metrics and by analyzing pertinent information to determine if further risk control practices are needed to enhance the safety of the system. Additional risk control practices can include modifying the cathodic protection system, patrols, procedure reviews, personnel qualifications, pipe and component replacement and public education.

Exhibit D

Task 3 - Identify Risk Control Techniques and Practices, Including Excess Flow Valves

Task 3 of the Risk Control Practices Work Group (RCP) is to identify risk control practices and determine the applicability and effectiveness of those practices. There is diversity of natural gas distribution systems in relation to the various materials and components used throughout the years and the different geographic locations throughout the country. With those differences in mind, it is necessary to understand that a risk control practice used by a gas distribution operator in one part of the country may not have application as a risk control practice to a company operating in another part of the country. It is necessary for an operator to choose which risk control practices are appropriate to protect the public for the system being operated.

The following list shows a variety of risk control measures and the threats being addressed. The column labeled “Summary” identifies how the practice helps to mitigate the specific threats. Some of the practices address all of the threats while others may only address one or two threats.

This list of risk control practices has been compiled. An operator must determine whether to use them to control risk in their distribution system, or to utilize other means. This would depend on the threats to the system, the geographic location of the distribution system, and other relevant factors.

For more guidance the operator should consider references such as the Gas Piping Technology Committee “Guide for Gas Transmission and Distribution Piping Systems – ANSI Z380.1,” Appendix G, “Industry Practices Questionnaire, Compilation of Responses” of the American Gas Foundation Study “Safety Performance and Integrity of the Natural Gas Distribution Infrastructure;” or the American Society of Mechanical Engineers (ASME) Standard ASME/ANSI B31.8 "Gas Transmission and Distribution Piping Systems;" and American Gas Association Gas Engineering and Operating Practices (GEOP) series. Many of these publications have a great deal of in depth information for an operator to consider when choosing practices to reduce risk and protect the public.

As discussed under Tasks 4 and 5, there is a need for guidance on synthesizing many of the existing risk control practices into an integrated distribution integrity management program.

Risk Control Practices

The following information was developed to show risk control practices used in natural gas distribution systems, identify the threats each practice addresses and summarize how the listed practice helps to mitigate the threat being addressed. This is a review of practices and an operator may choose to use any of these practices to control risk in their system. The operator should determine which practices are appropriate for its distribution system.

Risk Control Practices	**Threats Addressed**	**Summary**
Coordinating Committees		
Utility Coordinating Committees (Gas, Water, Electric, etc.)	Corrosion, Excavation Damage	Controls risk by allowing design engineers to discuss upcoming and on-going projects minimizing or eliminating potential interference problems. This allows for construction project designs to be less intrusive on distribution systems. Provides a forum for communication between facility owners and designers which may provide protection of distribution systems and components.
Design / Construction Coordinating Committees	Corrosion, Excavation Damage, Material and Welds	Controls risk by allowing design engineers to discuss upcoming and on-going projects, thereby minimizing or eliminating potential interference problems. This allows for construction project designs to be less intrusive on our distribution systems. It also provides a forum for communication between facility owners, designers and field personnel which may provide protection of distribution systems and components.
Utility Corrosion Control Committees	Corrosion	Controls risk by allowing corrosion control engineers to discuss upcoming and on-going projects minimizing or eliminating potential interference problems on cathodic protected distribution lines. This allows for construction project designs to be less intrusive on distribution systems and components such as anode beds and test stations. It also provides a forum for communication between facility owners, project designers and field personnel.

Risk Control Practices	Threats Addressed	Summary
Operator-Specific In-House Task Groups and Committees (incident command group, damage prevention, odorization, gas reliability /gas measurement, system design corrosion control)	Corrosion, Material and welds, Natural Forces, Excavation Damage, Other Outside Force Damage. Equipment and Operations, and Others	Controls risk by insuring that there is discussion and review of activities within these areas, insuring that the best possible results are being achieved. It allows for subject matter experts to discuss policies and procedures and activities related to the safe operation of distribution system operations.
Damage Prevention Coordinating Committees, Common Ground Alliance (Note: This practice was referred to the Excavation Damage Prevention Work Group)	Excavation Damage, Other Outside Force and Equipment and Operations	Controls risk by allowing operators to meet with project owners and contractors to discuss upcoming and on-going projects to reduce interference with other utilities. It also allows proper oversight of on-going construction projects. It also allows for proper planning of resources, assignments for mark outs and oversight of on-going construction projects. It allows for communication between facility owners and designers and excavators. There is an added layer of protection of distribution systems and components
Participation in One Call Systems (Note: This practice was referred to the Excavation Damage Prevention Work Group)	Corrosion, Natural Forces, Excavation Damage, Other Outside Force and Equipment and Operations	Controls risk by allowing the operator to identify and make arrangements to protect their distribution systems. It allows for communication between facility owners, designers and excavators. There is an added layer of protection of the distribution systems and components
Educational Outreach Programs		
Emergency Responders / Public Officials Liaisons / Groups	Natural Forces, Excavation Damage, Other Outside Force, Equipment and Operations	Controls risk by providing a forum for all parties to discuss their needs and educate each other in how to plan, recognize and react in the event they are faced with an emergency situation involving a natural gas distribution system. It allows for partnerships to be built prior to an event which leads to good communication between the operator and other agencies involved during an emergency situation. This would include, but is not limited to, major fires, emergency gas operations or storm conditions.

Risk Control Practices	**Threats Addressed**	**Summary**
Public Awareness / Education Programs	Natural Forces, Excavation Damage, Other Outside Force	Controls risk by informing the public how to plan, recognize and react to an odor of natural gas or other emergencies that may involve natural gas. It also raises the awareness of the presence of buried natural gas distribution lines and facilities.
Participation in Industry \ Regulatory Associations	Corrosion, Natural Forces, Excavation Damage, Other Outside Force Damage. Equipment and Operations, and Others	Controls risk by allowing for discussion of proper methods used within the industry. It allows for information exchange concerning rule changes, lessons learned and best practices to be followed. It also provides for a forum for communication between the industry and those regulating the industry. Problems and success stories are shared. This gives everyone the opportunity to know what problems may exist and allows the threat to be mitigated before an incident develops.
Personnel Training Programs		
Operator Qualification Programs (49 CFR Subpart N)	Corrosion, Natural Forces, Excavation Damage, Other Outside Force Damage. Equipment and Operations	Controls risk by insuring all personnel performing covered tasks have the knowledge, skills and ability to perform the task and to recognize abnormal operating conditions.
Welding and Plastic Fusion Qualification Programs	Material and welds Equipment and Operations	Controls risk by insuring all personnel performing these task have knowledge, skills and ability to perform the duties of joining pipe properly.
All Other Training and Safety Programs.	Corrosion, Natural Forces, Excavation Damage, materials and welds, Other Outside Force Damage. Equipment and Operations, and Others	Controls risk by instructing and inculcating employees in the proper methods and procedures to use when performing work on a distribution system. The program may include tailgate talks, meetings at the beginning and end of shifts, and annual refresher training programs.

Risk Control Practices	**Threats Addressed**	**Summary**
Training Seminars / Conferences	Corrosion, Natural Forces, Excavation Damage, Other Outside Force Damage. Equipment and Operations, and Others	Controls risk by allowing personnel to learn proper methods of construction, operation and maintenance on a distribution system. It allows for sharing of information from past experiences as well as progress on industry-related research and development of new methods and equipment.
Written Procedures Manuals	Corrosion, Natural Forces, Excavation Damage, materials and welds, Other Outside Force Damage. Equipment and Operations, and Others	Controls risk by providing clear direction in how to perform tasks as set by the organization
Operational Preventive Risk Control Measures		
Odorization Monitoring	Corrosion, Natural Forces, Excavation Damage, materials and welds, Other Outside Force Damage. Equipment and Operations, and Others	Controls risk by allowing for gas leak detection by anyone with a normal sense of smell to detect a leak in the system. By monitoring the concentration at which gas is detectable, the operator insures that gas can be easily detected by a person with normal sense of smell
Supervisory Control And Data Acquisition (SCADA) Systems	Natural Forces, Excavation Damage, Other Outside Force Damage. Equipment and Operations	Controls risk by providing a method of monitoring and controlling gas flows and pressures in the operator's system. With this equipment an operator may detect problems developing and may allow for reaction to avoid serious consequences.
Regulator Inspection Programs	Equipment, and Operations	Controls risk by Insuring safe operation of pressure operating equipment within the settings determined by the operator.
Valve Inspection Programs	Equipment, and Operations	Controls risk by confirming valve location, accessibility and operability.
Over Pressure Protection Planning	Equipment, and Operations	Controls risk by adding protection from over pressurization of a distribution system.
Practices to prevent damage to above ground distribution facilities	Corrosion, Natural Forces, Other Outside Force Damage	Controls risk through the use of, distribution patrols and leak survey to identify and mitigate unsafe conditions

Risk Control Practices	Threats Addressed	Summary
Pipeline Patrols	Natural Forces, Excavation Damage, Other Outside Force Damage Equipment and Operations	Controls risk by performing a visual inspection along the route of a distribution line looking for threats and unsafe conditions, and taking actions to mitigate the risk.
Corrosion Control, Inspections and Remediation Programs	Corrosion	Controls risk by monitoring the effectiveness of cathodic protection systems and mitigating problems in an operators system.
Material Tracking, Testing and Qualification Procedures	Natural Forces, Other Outside Force Damage. Equipment and Operations	Controls risk by recording the location of installed material and testing and certifying that material being used meet the standards for installation on gas distribution systems.
System Construction Installation Inspections	Equipment and Operations, Material and Welds	Controls risk by insuring the correct documentation of distribution line locations are recorded, the material being used is approved for gas installation and the distribution line is installed according to design plans and approved standards.
Leak Survey	Natural Forces, Excavation Damage, Other Outside Force Damage. Equipment, Operations, and Other	Controls risk by looking for leaks in a system before they develop into larger problems. Consideration should be given to the need for additional surveys according to the geographic area of the distribution line (e.g., frost/winter surveys), material (when appropriate) and other relevant factors affecting the risk.
Leak Management	Corrosion, Excavation Damage, Other Outside Force Damage. Equipment and Operations, and Others	Controls risk by the 5 elements of effective leak management program: *L*ocate the leak, *E*valuate its severity, *A*ct appropriately to mitigate the leak, *K*eep records, and *S*elf-assess to determine if additional actions are necessary to keep the system safe (see Appendix C - Effective Distribution Leak Management Framework)

Risk Control Practices	**Threats Addressed**	**Summary**
Distribution Line and Component Replacement Programs	Corrosion, Other Outside Force Damage. Equipment and Operations, and Others	Controls risk by determining where the threat to distribution lines and components is best addressed by replacement. Where replacement is chosen, the program should provide for prioritization of distribution system replacements (such as cast iron, bare steel and plastic subject to brittle cracking).
Installation of Excess Flow Valves	Natural Forces, Excavation Damage, Other Outside Force Damage	Controls risk by eliminating or reducing the flow of gas when the line is severed. The guidelines for installation of EFVs should be based on good engineering practice.
Operations and Maintenance Procedure Review Programs	Corrosion, Material and welds, Natural Forces, Excavation Damage, Other Outside Force Damage. Equipment and Operations, and Others	Controls risk by determining through adjustments to policies and procedures.
Quality Assurance and Quality Control Program	Corrosion, Material and welds, Natural Forces, Excavation Damage, Other Outside Force Damage. Equipment and Operations, and Others	Controls risk by periodically reviewing work done by operator personnel to determine the effectiveness and adequacy of procedures and modifying the procedures if deficiencies are found.
Emergency Plans	Corrosion Natural Forces, Excavation Damage, Other Outside Force Damage. Equipment and Operations, and Others	Controls risk by providing clear communications and direction to follow in the event of an emergency situation to control the consequence component of the risk equation.
Failure Investigations	Corrosion, Material and welds, Natural Forces, Excavation Damage, Other Outside Force Damage. Equipment and Operations, and Others	Controls risk by determining the cause of a failure and using that information to make adjustments to policies and procedures, as appropriate, to prevent a re-occurrence.

Exhibit E

Task 4 Report - Identify Current Federal Regulations, Identify Enhancement Needs, Identify Reference Standards Needs
&
Task 5 Report - Provide Suggestions to Address Enhancements in Regulations and References

I Regulatory Requirements and Consensus Standards to Address Threats

Current gas distribution pipeline regulations contained in 49 CFR 192 have evolved and developed over the past century from the American Standards Association B31.8, American National Standard for Gas Transmission and Distribution piping Systems (and its predecessor ASA B31.1.8). Most State agencies with pipeline regulatory authority adopted the B31.8 code. The objective of B31.8 has been to provide an effective set of practices for the design, construction, operation, and maintenance of gas systems which minimizes the occurrence of failures and improves public safety. The Minimum Federal Safety Standards (49 CFR 192) incorporated most of the provisions in B31.8. As a result, the B31.8 committee ceased active operations and evolved into the Gas Piping Standards Committee (now the Gas Piping Technology Committee (GPTC)). To assist operators in understanding how to comply with federal requirements, GPTC developed consensus guidelines for complying with the 49 CFR Parts 191 and 192. The guidelines are contained in the ANSI/GPTC Z380.1 Guide for Gas Transmission and Distribution Piping Systems.

1 49 CFR Part 192 Subpart requirements

The provisions of 49 CFR Part 192, Subparts A-M were reviewed with respect to their applicability to the eight threats (discussed supra.). The details are contained in Table 1 of this Appendix.

(a) Subpart A – General

This subpart addresses the scope, definitions, and applicability of Part 192. It also contains several sections that impact pipeline threats. Section 192.7 (Incorporation by reference) references pipe transportation, construction, materials, fabrication, and corroded pipe analysis specifications. These provide for minimum quality levels thereby reducing potential threats resulting from defective materials or fabrication.

(b) Subpart B – Material

Subpart B contains requirement for materials to be used in pipeline construction, qualification of steel pipe and components, plastic pipe and components, material marking, and pipe transportation. This also references the listed specifications for new materials and required qualification and limitations for use of older or used steel pipe. These requirements address the threat caused by installation of defective or improper pipe in a line.

(c) Subpart C - Pipe Design

Pipe design requirements for steel, plastic, and copper materials are contained in this subpart. For pipe, it covers design pressure, yield strength criteria, class location design factor, longitudinal joint factor, long term hydrostatic strength, pressure and temperature limits for plastic pipe, pressure limits for copper pipe, and limits of hydrogen sulfide content in the gas stream to minimize effects on internal corrosion of copper pipe.

(d) Subpart D - Design of Pipeline Components

Subpart D contains a wide range of requirements for pipeline components including valves, fittings, flanges, other manufactured components, extruded outlets, components fabricated by welding, compressor stations and equipment, pressure relief devices and requirements to control delivered gas pressures, and vaults. It also covers limits of taps in cast iron or ductile iron pipe, flexibility requirements to address thermal stresses caused by expansion or contraction, excessive bending, and loads at points of connection, as well as requirements to protect exposed pipe and requirements for emergency shut off valves. Due to the wide scope of Subpart D, it impacts a number of the eight threats.

(e) Subpart E - Welding of Steel in Pipelines

Subpart E contains requirements for welding, welder qualification, restrictions on miter joints, weld testing and inspection, repair, and nondestructive testing. Proper attention to all of these criteria is required to produce acceptable quality field and fabrication welds. The requirements address threats due to defective pipe girth weld and defective fabrication, as well as weldments to meet the more demanding service conditions created by low ambient temperatures.

(f) Subpart F - Joining of Materials Other than by Welding

This subpart contains joining requirements and limitations for cast iron, ductile iron, copper and steel materials. Significant requirements address plastic pipe joining including procedure and personnel qualifications. With respect to pipeline threats, these criteria pertain to gasket/O-Ring failure and consideration of longitudinal forces and joint expansion/contraction.

(g) Subpart G - General Construction Requirements for Mains

Construction requirements contained in this subpart include the requirement for written construction standards, construction and material inspection, pipe installation support, ditch alignment, backfill, pipe repair and limitations, hazard protection, pipe installation, clearance and cover. The threat created by heavy rains or floods is addressed in §192.317 and §192.327 by requiring hazard protection and sufficient depth.

(h) Subpart H - Customer Meters, Service Regulators, and Service Lines

This subpart contains requirements for location and installation of service lines, service line valves, and connections to mains, installation of customer meters, service regulators, excess flow valve (EFV) performance and customer EFV notification requirements.

(i) Subpart I - Requirements for Corrosion Control

This subpart is focused on internal, external, and atmospheric corrosion control as applied to metallic materials. More specifically, it covers cathodic protection systems, coatings, corrosion monitoring, electrical isolation, remedial measures, and records. The emphasis of requirements is on external corrosion.

(j) Subpart J - Test Requirements

Subpart J applies to strength verification and leak testing requirements of new, relocated, or replaced pipeline segments. It is aimed at detection of defects that may remain after construction is completed. Threats impacted by requirements include previously damaged pipe, defective pipe seam, defective pipe, defective girth weld and defective fabrication weld.

(k) Subpart K- Uprating

This subpart describes what must be done to uprate pressure of piping facilities.

(l) Subpart L- Operations

This subpart describes operations requirements for pipeline facilities.

(m) Subpart M- Maintenance

This subpart describes maintenance requirements for pipeline facilities. Major sections describe requirements for patrols, leak surveys, and inspections of components to ensure their operability.

(n) Subpart N - Qualification of Pipeline Personnel

This subpart contains requirements for qualification of pipeline personnel who perform tasks that affect "the operation or integrity of the pipeline" (49 CFR 192.801). This new set of requirements became effective August 27, 1999, but the written qualification program was not required until April 27, 2001 and operators did not have to complete the qualification of individuals performing covered tasks until October 28, 2002 (49 CFR 192.809). The intent of this subpart is to address the threats due to employee error. As more experience is gained with these programs, the results can be evaluated and any adjustments made.

(o) Subpart O - Pipeline Integrity Management

This subpart addresses integrity management of transmission pipelines. While it is not applicable to distribution pipelines, it was reviewed with a view to incorporating into distribution integrity management the important risk management principles.

2 State Regulations and Requirements

The following list of State requirements imposed on distribution operators (regulations, compliance orders, rate case agreements, and other actions) and operator practices that result in operators evaluating their system components to determine whether they may have materials or conditions susceptible to certain identified threats. Operators develop and implement mitigation measures or risk control practices to address those situations. The list of resultant programs and practices include prevention, detection and mitigation actions and activities. The list has been developed from surveys of State requirements and programs identified by State regulatory officials that exceed minimum federal pipeline safety regulations. Items that relate specifically to the threat of damage to pipeline facilities due to excavation activities are noted as being within the purview of the Excavation Damage Work Group.

(a) Pipe Replacement and Removal Programs - Mains

- (i) Cast iron, focusing first on small diameter (8" and less), higher pressures
- (ii) Bare and unprotected steel, concentrated on smaller diameter (thinner wall)
- (iii) Plastic pipe susceptible to cracking and brittle failure, Adyl A, Century, ABS
- (iv) Redundant mains (usually associated with former franchise boundaries)

(b) Pipe Replacement Programs – Services and appurtenances

- (i) Cast iron
- (ii) Steel, wrought and ductile iron, focusing on specific installation dates
- (iii) Service tees at the main associated with copper inserted lines
- (iv) Lamp services and stub services
- (v) Certain couplings (vintages not designed for gas service)
- (vi) Elimination of inactive service lines (generally between 3 and 7 years)
- (vii) Elimination of capped live service lines to abandoned buildings
- (viii) Removal of mercury seal regulators

(c) Leak Management Requirements and Programs

- (i) Leak classification requirements
- (ii) Documentation of leak migration pattern
- (iii) Time limits for repairs (associated with class of leak)
- (iv) Periodic leak location monitoring (intervals associated with class of leak)
- (v) Recheck of leak repair location (verification of repair effectiveness)
- (vi) Limits for leak backlogs (generally pending repair at year end by class of leak)
- (vii) Leak and odor emergency response time goals
- (viii) Accelerated leak surveys based on history, environmental factors, paving
- (ix) Frost surveys
- (x) Broken main surveys

(d) Damage Prevention Requirements and Programs (Excavation Damage Group)

(i) Increased cover requirements in agricultural lands or in other areas where excavation activity is likely
(ii) Increased patrols of excavation projects/watchmen assigned to locations
(iii) Identification of habitual offending contractors
(iv) Notices to offending contractors

(e) Cathodic Protection Practices and Programs

(i) Installation of anodes to take advantage of excavations
(ii) Adding CP and clearing shorts to pre-1971 coated pipe to prolong life

(f) Other Programs

(i) Installation of barriers to protect meters and regulator sets and surveys to inspect for vehicular damage susceptibility

3 Detailed Working Papers and Analysis

The information contained in this spreadsheet was generated by the members of the Risk Control Practices Work Group (RCP) based on their individual reviews and covered 49 CFR 192, the Guide for Gas Transmission and Distribution Piping Systems and certain additional references reviewed. The responses from the members were combined into the following spreadsheet. Each of the sections was discussed and final actions by RCP are noted in the last column. All other comments should be considered preliminary and not final action of the RCP. It should be noted the Excavation Damage Work Group has responsibility for excavation damage issues, and that, for the most part, issues related to that threat were referred to that group.

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
Subpart A					
	192.3	Definitions	N/A	Threats defined on PHMSA F 7100.1, F 7100.1-1, AGF Study, Allegro Report and ASME B31.8S.	
	192.7	Incorporation by Reference	N/A	Allows incorporation of existing or new standards into code by reference.	
	192.7	Incorporated by reference		GPTC Guide Material could be referenced for certain code sections as a resource to the Operator.	Requires further discussion regarding how PHMSA might adopt or incorporate guidance material within Part 192.
	192.13	General	Plans, Procedures and Programs	Often misused, however this does address effectiveness in that it requires operators to maintain and follow the safety and integrity requirements of the code through their own plans, procedures and programs.	

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
	192.16	Corrosion, mechanical/equipment, excavation damage	Written notification to customer	Pending Final rule on Public Awareness (Docket No. RSPA-03-15852) should enhance customer's awareness of leaks and hazards associated with leaks.	Final rule has ~~not~~ been issued. No action necessary.
	192.55	Use of used steel pipe for distribution pipe.		Used pipe should not be allowed for new construction.	RCP Group determined no failure data exists to act on this issue.
Subpart B					
	All	Materials	Material Specifications	Adequate - pertains mostly to manufacturing related defect threats. See AGF Study Table 5-3 for other threat applicability.	
Subpart C					
	(192.105, 121, 125 and 143)	Excavation damage		Providing gas pipelines and components with greater wall thickness might produce some increase in resistance to damage by excavation equipment.	RCP Group determined 192.103 adequately addresses this issue. Operators may consider this as a risk control practice.
	192.125 (d)	Pipe Design internal corrosion	Copper without an internal lining may not be used if gas is carrying more than 0.3 grains/ 100 cu ft of hydrogen sulfide	This is okay for initial design and installation, but this requirement could be missed if an Operator was solely relying on Section 192.475 Internal Corrosion direction. I view the following as a clarity issue and not an inherent problem with the code since internal corrosion in LDC systems is rare.	RCP group determined this is not a significant integrity issue warranting further action.
Subpart D					
	192.159	Design of Pipeline Components outside force - all material types	Flexibility must be designed into the pipeline system	No standards/guidelines are referenced. GPTC guide material provides direction for Operators.	Comments for both 192.159 and .161 deal primarily with transmission lines. However, the RCP group determined that the GPTC guide material was adequate.
	192.161	Outside force - all material types	Each pipeline must have enough anchors or supports	No standards/guidelines are referenced. GPTC guide material provides direction for Operators.	RCP Group determined guidance material is adequate.

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
	192.181	Possible increased risk (consequence) due to inability to isolate station.	Regulator station inlet/outlet valves	No guidance for high pressure distribution valve spacing, nor requirements for emergency shut-off valves on outlet side of regulator stations. GPTC does have guidance for this.	The RCP group determined GPTC guidance appears adequate.
	192.191	Plastic fittings	Enhanced test protocols for plastic-mechanical fittings	ASTM needs to take action to enhance performance test protocols (for components, burst tests, etc.) for these type fittings. Specific protocols for the evaluation of elastomer related issues (gasket & O rings) should be incorporated. Also, requirements for permanent marking of pipe and appurtenances so that materials can be gotten back to when there are indications of problems in a proactive manner	RCP group determined ASTM needs to take action to enhance performance test protocols (for components, burst tests, etc.) for these type fittings, to incorporate protocols for the evaluation of elastomer related issues (gasket & O rings). Also, add requirements for permanent marking of pipe and appurtenances so that materials can be redressed in a proactive manner should indications of problems be identified.
	All	Design of Pipeline Components	Design Specifications for Pipeline Components including Valves, Flanges, Fittings, Compressor Stations, Vaults and Pressure Control and Relief Devices.	Adequate - pertains mostly to equipment malfunction threats. See AGF Study Table 5-3 for other threat applicability.	
Subpart E					
	NYS	Construction-Related Defects Steel Pipe	QC of welding on distribution	No provision for field checking (NDT) of welds	

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
		Construction-Related Defects Steel Pipe	QC of welding on distribution	No provision for field checking (NDT) of welds; visual and welder performs this test, should be performed by different persons.	RCP Group determined there is no data to indicate that improper joints are a major cause of incidents.
	All	Welding	Welding Qualifications and Testing	Adequate - pertains mostly to construction related defect threats on steel pipe. See AGF Study Table 5-3 for other threat applicability.	
Subpart F					
	192.281-287	Joining of Materials Other Than by Welding	Plastic Pipe joining qualifications and inspection of joints	Adequate - pertains mostly to construction related defect threats on plastic pipe. See AGF Study Table 5-3 for other threat applicability.	
Subpart G					
	192.303-315, and 192.319-325	Construction, Inspections and Installation Requirements	Construction, Inspections and Installation Requirements for mains.	Adequate - Addresses construction related defect, incorrect operations and mechanical damage threats.	
	192.313 and 315 for steel mains) and miter bends (49 CFR 192.233	welding, construction		Allowing a miter weld which deflects more than 12½° should never be allowed regardless of pressure (192.233(c)), and should never be anywhere near 90°. Also, cutting a notch out of a pipe, bending it, and welding the pipe back together should never be allowed because the outside forces can cause the weld to crack.	RCP Group determined there is a gap in the code but it is not of a nature that needs to be addressed in this safety enhancement effort.
	192.317(a)	Protection from Hazards	Practicable steps to protect mains from hazards.	<u>Code section</u> should specifically mention hazards due to frost, drought, and heat conditions. GPTC <u>guide material</u> needs to specifically address these hazards.	RCP Group determined that no further code material is needed but that guide material is needed.

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
	192.317 (b)	Outside force	Aboveground main must be protected from accidental damage by vehicular traffic	Code is adequate as it requires Operators to place main at a safe distance or by installing barricades. GPTC GM Appendix 192-13 provides additional guidance. Currently "buried" within section 7-Other guide material, this material could be re-formatted to highlight guidance to prevent vehicular damage to the main.	RCP Group concurs that GPTC material needs to be modified. The Allegro study identified damage to M&R sets as an issue, but data was insufficient to determine the nature of what needed to be addressed.
	192.317	Protection from Hazards	Practicable steps to protect mains from hazards.	Adequate - Addresses Mechanical Damage and Outside Force/Weather related threats.	
	192.325	Outside force	Underground clearance for mains	No minimum clearance specified; GPTC has guidance, but does not specify min. clearance.	
	192.325	Outside force	Underground clearance for mains	Maintain at least 12 inches of separation between gas service lines and other buried utilities, with burial beneath the actual or anticipated depth of wires or cables where practical.	RCP determined this is not a major issue for a code gap but recommends GPTC consider including guidance addressing what should be desirable clearances where practical. See 192.361.
	192.327	Cover	Cover requirements for mains	Adequate - Addresses excavation and mechanical damage threats.	
Subpart H					
	All	Service line construction		There is no requirement for written construction standards.	This must be revisited by the RCP group for resolution.
	192.353	Outside Force/Weather Steel Pipe Outside Force/Plastic Pipe	Protection of customer M&Rs	Does not specifically disallow location in open areas (property line, etc.).	This item needs further analysis of data from the Allegro study. RCP group recommends contacting the liaison to the Data group to obtain updated analysis to evaluate code requirement(s).

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
	192.353 (a)	Customer Meters, Service Regulators, and Service Lines, Outside force	Protect meter and service regulator from damage by vehicles	Vehicle damage was added to code section under Amdt. 192-93. Refer to Final Rule to Docket RSPA-02-13208 for detailed discussion on this threat.	RCP Group determined that data from Allegro study needs further clarification in order to better address this issue.
	192.353 and 192.355	Meter Location and Protection from Damage	Meter location and protection requirements	Adequate - Addresses Mechanical Damage (vehicular damage) and Outside Force/Weather related threats on meters.	RCP Group reviewed the GPTC guide material and determined it addresses ice blockage of service regulators.
	192.357 and 192.359	Meter and Regulator Installation	Installation requirements for customer meters and regulators	Adequate - Addresses Mechanical Damage, Manufacturing Related Defects and Equipment Malfunction threats for meters and regulators.	
	192.361	Service Line Installation	Installation requirements for service lines	A deeper burial depth for gas lines is needed which would put them below the other utilities, thus reducing the probability of damage. NESC Table 352-1 requires electric service lines and communications lines be buried 24” deep – deeper than the existing 12” minimum cover for gas service lines (Code change)	RCP Group determined this should be considered as a risk control practice where appropriate; this is not a code issue. GPTC and Common Ground Alliance also contain relevant guide material.
	192.361	Service Line Installation	Installation requirements for service lines	Maintain at least 12 inches of separation between gas service lines and other buried utilities, with burial beneath the actual or anticipated depth of wires or cables where practical.	RCP determined this is not a major issue for a code gap but recommends GPTC consider including guidance addressing what should be desirable clearances where practical.
	192.363 and 192.365	Service Line Valve requirements	Service line valve material, design and location requirements	Adequate - Addresses Mechanical Damage, Manufacturing Related Defects and Equipment Malfunction threats for service line valves.	

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
	192.365	Increased risk (consequences) due to inability to access valve in an emergency	Location of service line valves if feasible outside	Allows valves inside on HP and on large services- currently no GPTC guidance, possibly require outside when size of line is greater than 2", or for public buildings	RCP Group determined that a code change was not necessary but that further GPTC guidance is recommended.
	192.367-377	Service Line Requirements	Service line requirements by type of pipe.	Adequate - Addresses Excavation Damage, Mechanical Damage and Outside Force/Weather related threats for services.	
	192.373	Increased risk by installation of material or failure	CI and DI services	Installation of CI service lines > 6" allowed; modify code to eliminate or forbid cast iron installation regardless of diameter. Is this allowance needed for any reason?	RCP Group did not believe this is a problem and a code change is not needed.
	192.381		EFV performance standards	The need exists to update performance standards.	RCP determined that the existing performance requirements for EFVs is adequate.
	192.383	Excess Flow Valve Customer Notification	Excess flow valve is designed to stop the flow of natural gas automatically if the service line breaks	Existing code is adequate and should be considered as a preventative measure within Distribution integrity management	
	192.383	Excess Flow Valve Customer Notification	Excess flow valve is designed to stop the flow of natural gas automatically if the service line breaks	Existing code is inadequate and should require their installation without notification where practical as long as this practice allows for rate recovery.	RCP Group determined no code change is necessary, but that EFVs should be considered as a risk control practice option.
Subpart I					
	192.465(e)	External corrosion	Remedial measures for areas of active corrosion	Does not specify time frame for remedial actions when areas of active corrosion are identified; GPTC guidance needed in this area.	RCP group determined that GPTC guidance is needed in this area.
	All	External, internal and atmospheric corrosion	Control corrosion on metallic pipelines	Several sections of Subpart I were addressed by NAPSR and Industry via Docket RSPA-02-13208 and RSPA PS-124 (1992).	RCP group determined that the existing code section is adequate.
	All	Corrosion Control	External, Internal and Atmospheric corrosion control requirements	Excellent - Addresses all corrosion related threats. See AGF Study Table 5-3 for other threat applicability.	

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
Subparts J, K, & L				Support SIRRC II efforts to clarify code requirements. Eliminate confusing, ambiguous, and conflicting language: - Clarify the distinction of the sections and paragraphs applicable to transmission and those applicable to distribution - Ensure code requirements for uprating and establishing the MAOP of distribution systems are clarified as a distinct set of rules. - Simplify and facilitate compliance with rule provisions while ensuring safety is maintained or enhanced. - Eliminate confusing cross-references	RCP Group determined that PHMSA rulemaking is needed to address SIRRC II petition to PHMSA, and that the petition addresses safety integrity issues which could be included within a proposed rule change to address distribution safety integrity enhancement needs.
Subpart J					
	All	Testing	Testing requirements for mains and services	Adequate - pertains mostly to manufacturing and construction related defect threats on mains and services. See AGF Study Table 5-3 for other threat applicability.	
Subpart K					
	192.557	Risk of increased leaks due to higher pressure	Procedure for uprating pipelines to < 30% SMYS	Allows uprating of CI pipe; additional GPTC guidance is needed.	RCP Group determined no code change is required however, guide material is needed for this issue.
	All	Uprating	Uprating requirements for mains and services	Adequate - pertains mostly to corrosion, equipment malfunction, manufacturing and construction related defect threats on mains and services. See AGF Study Table 5-3 for other threat applicability.	

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
Subpart L					
	192.605	Procedures	Procedure manual requirements	192.605(e) specifies the requirement to include surveillance and accident investigation in the operator's O&M procedure manual. The language of this paragraph and the referenced sections does not clearly convey the concept of a risk-based distribution integrity management process that includes gathering system knowledge (surveillance), analyzing and prioritizing integrity threats and controlling the integrity related risks. Gap: No list of specified items will ever be complete. GPTC Guide has 61/2 pages of additional detail	RCP Group believes the following may form the basis for a distribution integrity management plan and suggests a new code section which includes requirements from sections 192 .605, 613, 614, and .617, along with the following 7 program elements: 1) Written Program 2) Identify Threats 3) Risk Assess Threats 4) Apply P&M Measures 5) Measure Performance 6) Evaluate Effectiveness 7) Reporting
	192.613	Continuing Surveillance - All threats	General requirements for analysis and responses to integrity related threats	Code Section open to wide interpretation. The language of this section is broad and non-specific. Section does not clearly convey the concept of a risk-based distribution integrity management process that includes gathering system knowledge (surveillance), analyzing and prioritizing integrity threats and controlling the integrity related risks.	See actions to be taken under section 192.605.

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
	192.614	Damage Prevention	Excavation damage prevention requirements	This is the greatest threat to distribution integrity and requires the most attention. This section provides requirements for operators to participate in one-call programs and locate their facilities in advance of excavation. The operator is one of many stakeholders and the only one subject to this regulation, though all stakeholders share the responsibility for vigilance and action to prevent damage Additional state rules are needed to address this threat. Some states have rules, organizations and enforcement actions which have proven effective in preventing excavation damage. Others do not. The Common Ground Alliance is a voluntary organization helping to control excavation damage by bringing all stakeholders together to improve the excavation damage prevention process. Most of the improvement is outside the scope of 192.614, so there is a gap in state rules and practices. GPTC Guide has 5 1/2 pages of details to consider in developing and implementing a program.	The RCP group is not charged with addressing excavation damage safety enhancements. From its cursory review, it appears as if most of the remaining improvement is outside the scope of 192.614, so there is not a code gap in this section. It appears to the RCP group that a gap in state rules and practices that encompass a wider range of excavation stakeholders exists. The RCP group recommends transmitting this suggestion to the excavation damage group to address this suggestion.
	192.615	Emergency Response	Emergency response requirements	Adequate - This section addresses the consequences of failures and how to control that part of the risk equation.	
	192.615	Excavation Damage Outside Force/Weather St Outside Force/Weather CI Outside Force/Weather Pl Mechanical Damage (?) Equipment Malfunction Incorrect Ops & Op	Write procedures, identify & classify, establish communication & liaison, provide response	Gap- no direction on how to identify or classify emergency notices. GPTC Guide provides 6 1/2 pages of details for consideration plus a sample emergency plan format in an appendix.	RCP Group believes no code change is required as there is adequate guidance in the GPTC guidance.

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
		Error(?)			
	192.616	All Threats	Operator to establish a continuing educational program for stakeholders to recognize a gas pipeline emergency	The goal of the pending final rule on Public Awareness (Docket No. RSPA-03-15852) is to enhance the effectiveness of an Operator's Public Education program.	
	192.616	Excavation Damage Equipment Malfunction Outside Force/Weather St (?) Outside Force/Weather CI (?) Outside Force/Weather Pl (?) Incorrect Ops & Op Error(?)	Write program, educate the public	No gaps. GPTC Guide provides a list of information to be communicated, and methods for evaluating the program effectiveness	
	192.617	Investigation of failures	General requirements for failure cause analysis	This section may include root cause analysis and requirements for corrective and preventive actions stemming from that analysis. It is an important element of distribution integrity management.	
	192.617	Investigation of failures	General requirements for failure cause analysis	Various interpretations by Operators - some only apply process to reportable incidents. Section needs clarification that the evaluation required by this section in certain circumstances should be applied to leaks as well as incidents. GPTC may need further guide material language to address the types and nature of failures which should be analyzed for root cause.	RCP Group believes this section does not need a code change but needs GPTC guidance as to the types of failures (including leaks) which may need to be investigated and trigger a more rigorous type of analysis.

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
	192.619	Construction-Defects Plastic Manufacture-Defects Plastic Construction-Defects Steel Manufacture-Defects Steel	Determine MAOP	Gap - it is not clear that this section applies to all pipelines and must be followed before using 192.621 or 192.623 for distribution systems.	RCP Group believes this gap is not critical to distribution IMP efforts and recommends taking no action at this time on 192.619 nor with .621. As indicated earlier in this spreadsheet, the RCP group supports the SIRRC II petition involving code changes in this area.
	192.621	Construction-Defects Plastic Manufacture-Defects Plastic Construction-Defects Steel Manufacture-Defects Steel	Determine MAOP	GPTC Guide directs operator to 192.619 first (see "gap" in 192.619)	
	192.619-623	MAOP	MAOP determination requirements	Adequate	
	192.625	Odorization	Odorization and odorant monitoring requirements	Adequate	
	192.625	Odorization	Odorization and odorant monitoring requirements	Some States require more stringent odorization level requirements.	RCP Group believes this may be a risk control practice which operators may consider.
	192.627 and 192.629	Tapping and Purging	Qualification and procedure requirements	Adequate - These sections address the Incorrect Operations threat.	
	192.627	Incorrect Ops & Op Error Mechanical Damage	Qualify crew	GPTC Guide has 2 pages of guide material on pre-tapping activities and other considerations	

Part 192 subparts	**Identify Specific section**	**Brief description of safety integrity requirement, risk or threat**	**What is the required activity expected of the operator?**	**Brief description why code requirement is adequate or is a gap- either regulations or reference materials**	**RCP Group Action (if necessary)**
Subpart M					
	192.703	All Threats	Repair or replace unsafe pipe	No specifics on how to determine unsafe pipe; no criteria on what is a hazardous leak (leak classification); Gaps- terms "unsafe", hazardous leak", "promptly" not defined. GPTC Guide Appendix 11 has sufficient guidance on determining unsafe pipe and on leak classification and repair; References: AGA XL8920 & PRCI L51717	To address this issue, RCP has prepared a leak management framework document (see Appendix C - Effective Distribution Leak Management Framework). *__L__*ocate the leak, *__E__*valuate its severity, *__A__*ct appropriately to mitigate the leak, *__K__*eep records, and *__S__*elf-assess to determine if additional actions are necessary to keep the system safe
	192.707	Excavation Damage	Place, maintain line markers	Gap - "close as practical" not defined. GPTC Guide Appendix 13 gives typical examples for placement of line markers, further guidance on "close as practical" should be given.	GPTC Guide Appendix 13 lists examples of locations for placement of line markers; further guidance on spacing to address "close as practical" should be developed to address change of direction and line of sight considerations.
	192.721	All	Main patrolling	Type, frequency, and purpose of patrols not specified except for mains subject to physical movement GPTC Guide provides what to look for and a list of locations for increased patrol vigilance.	RCP group determined that GPTC guidance material is adequate, it is a risk control practice available for operators to consider, and no further action is recommended.

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
	192.723	External Corrosion Coated External Corrosion Bare St External Corrosion CI Internal Corrosion Excavation Damage Outside Force/Weather St Outside Force/Weather CI Outside Force/Weather Pl Mechanical Damage Equipment Malfunction Construction-Defects Steel Manufacture-Defects Steel	Distribution leakage surveys	Does not specify leak detection equipment; some operators utilize gas-trac type devices GPTC does provide guidance. GPTC Guide Appendix 11 provides details of how to conduct a leak survey and how to classify leaks found for future management. Guidance on limitations/sensitivities is needed.	RCP group determined there is an issue with the code requirement; it should specify that the word "appropriate" should be inserted before "leak detection equipment". In (b)(1) and (2). RCP group determined that GPTC guidance material is needed regarding limitations or sensitivities of leak detection equipment.
	192.725	External Corrosion Coated External Corrosion Bare St External Corrosion CI Internal Corrosion Excavation Damage Outside Force/Weather St Outside Force/Weather CI Outside Force/Weather Pl Mechanical Damage	Test for reinstating service lines	GPTC Guide Appendix 10 supplies a table of test conditions for service lines	
	NYS	Equipment Damage	Service regulator inspections	Not required by Part 192; required in NY 255.744	
	192.727	Incorrect Ops & Op Error	Disconnect, purge, fill, seal	GPTC Guide Appendix 12 details considerations for planned shutdown including planning, pre-shutdown activities, venting and making safe worksite conditions	
	192.727(d)	External Corrosion Coated External Corrosion Bare St External Corrosion CI Internal Corrosion Excavation Damage Outside Force/Weather St Outside Force/Weather	Handling of inactive service lines	Risk of losing track of inactive facilities Part 192 does not address handling of inactive service lines (duration, maintenance, etc; required in NY 255.726).	RCP group believes no code change is needed, however further GPTC guidance material is recommended to address the tracking, maintenance and duration of inactive service lines.

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
		Cl Outside Force/Weather Pl Equipment Malfunction			
	192.739	Equipment Damage Incorrect Ops & Op Error	Inspect, test	GPTC Guide provides details on what to look for during an inspection	
	192.741	Equipment DamageIncorrect Ops & Op Error	Provide telemetry or pressure gages, determine necessity	GPTC Guide detail maintenance of instruments, suitability of telemetry, abnormal conditions	
	192.743	Equipment Damage Incorrect Ops & Op Error	Test, calculate	GPTC Guide provides for determining feasibility of in-place testing, references for in-place testing, capacity determination in lieu of testing	
	192.747	Outside Force/Weather St Outside Force/Weather Cl Outside Force/Weather Pl Mechanical Damage Equipment Malfunction	Check, service, designate alternate		
	192.747	Equipment Malfunction	Distribution line valve inspection	Does not require recording the detailed location of valve, or verification of location during inspection.	RCP group determined that GPTC has adequate guidance and no further code change is necessary.
	192.747	Equipment	Operator to take prompt remedial action to correct any valve found inoperable	Refer to Final Rule to Docket RSPA-02-13208 for detailed discussion on this threat. The preambles to final rules are an excellent place to obtain guidance on changes to rule. Downside is when the rule is several years olds and the preambles are not readily available.	
	NYS	Equipment Malfunction	Service line valve inspection	Not required by Part 192; required in NY	

Part 192 subparts	Identify Specific section	Brief description of safety integrity requirement, risk or threat	What is the required activity expected of the operator?	Brief description why code requirement is adequate or is a gap- either regulations or reference materials	RCP Group Action (if necessary)
	192.749	Outside Force/Weather StOutside Force/Weather CI Outside Force/Weather PlMechanical Damage	Inspect vaults	GPTC Guide has suggested entry procedures.	
	All	Maintenance	Inspection and maintenance requirements.	Adequate - Addresses the inspections needed to gather system knowledge information, such as leakage survey and patrolling.	
	192.751 and 192.753	Maintenance	Cast Iron joints and protective measures	Adequate - These sections address the Mechanical and Outside Force/Weather related threats to cast iron pipe.	
	192.753	External Corrosion CI Outside Force/Weather CI	Seal cast iron joints	GPTC Guide Appendix 18 covers many issues/activities appropriate to cast iron pipe	
	192.755	Outside Force/Weather CI	Replacement of disturbed CI pipe	No requirements in Part 192 for replacement of CI main exposed and undermined, or parallel to excavation; required in NY (255.756) GPTC has guidance but does not specify width of crossing excavation or sizes of CI; AGA XL8920 may cover this.	RCP group recommends adding code wording to 192.755 to provide an option of protecting or replacing undermined cast iron pipe. The RCP group determined that no further guidance was needed at this time.
	192.755	Outside Force/Weather CI	Protect	GPTC Guide Appendix 18 covers many issues/activities appropriate to cast iron pipe. Appendix 16 provides substructure damage prevention guidance.	
Subpart N		Incorrect operations	Qualification of personnel and recognizing abnormal conditions		Due to the relatively new section and lack of experience implementing the requirements, no effort was made by the RCP group to perform a code gap analysis of this subpart.

Part 192 subparts	**Identify Specific section**	**Brief description of safety integrity requirement, risk or threat**	**What is the required activity expected of the operator?**	**Brief description why code requirement is adequate or is a gap- either regulations or reference materials**	**RCP Group Action (if necessary)**
Subpart O					
	192.911	IM program elements include general threat analysis requirements.	Requirements for IM program	Consider a small subset of these elements for distribution IM QAT-Distribution Integrity Management - Steering Committee has identified 7 potential elements: 1) Written Program 2) Identify Threats 3) Risk Assess Threats 4) Apply P&M Measures 5) Measure Performance 6) Evaluate Effectiveness 7) Reporting	Subpart O was developed for application to transmission lines. No detailed gap analysis was performed by the RCP group. The RCP group recognized it as a resource to the distribution effort, and extracted wording that may be applicable for distribution. See remarks in section 192.605.
	192.917a	Threats are in four categories and follow B31.8S	Consider all threats to could affect	Possibility of selecting threats applicable to distribution from B31.8S	RCP is using the threats or causes of leaks and failures contained in the PHMSA annual leak and incident reports.
	192.917e	Specific threats to be addressed	TPD, Cyclic, Manufacturing and construction, ERW, corrosion	Some subset of these specific threats could form a basis for Distribution IM	
	192.917c	Risk Assessment	B31.8S requirements	Use B31.8S for distribution risk assessment requirements modified for distribution characteristics - assess by threat instead of by individual line segment	
	192.923	DA for ECDA, ICDA, SCCDA only	B31.8S and NACE	Possible starting point for Distribution DA	
	192.925	External Corrosion DA	Requirements for IM program	Includes reference to NACE but is more stringent	

II Research and Development Suggestions for Distribution Integrity

The RCP Group obtained lists of Research and Development projects and development needs from the outcome of the Office of Pipeline Safety Research and Development Forum, from the Northeast Gas Association (NGA) and from the American Gas Association (AGA). From those lists the RCP Group identified areas which may provide the greatest impact for gas distribution safety improvements and that should be considered for support.

1 PHMSA Research and Development Forum

The following areas and issues were identified during the PHMSA R&D forum as being in need of R&D support to improve safety.

(a) Leak Detection

(i) Assessment of significance of small leak problem

(ii) New technologies for real-time monitoring and detection of small leaks

(iii) Develop hand-held devices and methods for pinpointing location and migration patterns

(b) Sensor Technology

(i) Develop improved understanding of performance characteristics of existing technologies and examine emerging technologies to improve results

(ii) For unpiggable lines, need to improve power and communications, integrate platform and sensor package design, and develop guidelines for cleaning

(iii) Methods for inspecting cased pipes

(iv) Assess needs for new technologies for inspection of non-metallic pipe

(v) Considerations for small diameter pipelines

(c) Mechanical Damage

(i) Enhance methods of inspection and assessment for qualitative screening and ranking

(ii) Develop tools and methods of inspection and assessment for quantitative life predictions and prioritization of severity damage

(iii) Identify methods to locate and repair damage in difficult to inspect areas

(iv) Develop proper definitions for cracks and other damages

(v) Design tools to inspect pipes of various steel grades and non-metallic pipe

(d) When to Repair

(i) Identify technologies needed to support repair decisions

(ii) Investigate how to mine existing datasets with goal of providing improved industry guidance

(iii) Need to transfer technologies to industry to influence standards and regulatory activities

(e) How to Repair

(i) Guidance on proper selection of composite and other repair techniques, develop a tracking database and state of industry report

(ii) Consider drivers for selection of repair technologies

2 Northeast Gas Association Research and Development Projects

Northeast Gas Association (NGA) R&D Projects applicable to distribution safety are described below. NGA identifies its top R&D needs as follows:

(i) Improved pipe location capabilities

(ii) Development of 3rd party damage prevention monitoring and prevention devices (such as the "pigpen" devices installed by keyhole technique in selected sensitive pipe locations)

(iii) Improved wireless communication for transmitting data collected at various points on a distribution system (vibration from 3rd party construction, moisture indications, flow rate, pressures, etc.) to provide real time sensing of conditions in the distribution system.
(iv) Advancing data collection efficiency to enable cost efficient risk assessment. The issue involves identifying a process for determining how much data to collect, what is necessary, how to collect the data, how is it segmented etc.
(v) Improving the capability of hand held devices for evaluating graphitization of cast iron pipes. Such data can then be utilized in assessing priorities for maintenance and replacement strategies.

The following are R&D projects NGA is sponsoring and seeking further support.
(i) Explorer II - This system adds to the capabilities of the EXPLORER™ platform already developed for the visual inspection of 6" and 8" distribution mains, by integrating a sensor able to provide non-destructive evaluation capabilities of the pipeline. May also be used to evaluate the condition of pipelines adjacent to those being replaced to obtain data on their remaining life and corrosion rates.
(ii) Handheld Pipe Locator - The handheld pipe locator would offer significant benefits related to the costs of third party damage, the costs for repeat locates and excavations to verify the presence or absence of substructures and improved safety. Capable of locating plastic, steel, cast iron and other facilities as small as ½" to as large as 24" in diameter. Unlike current and recently commercialized pipe location devices, this handheld tool must be able to function using a free floating antenna that does not require contact to the ground, is lightweight (less than 15 lbs.), has low power requirements and does not surpass a measured radiation level while still achieving the desired performance, and producing data easily used by a technician.
(iii) PIGPEN – An infrasonic sensor system for detecting potential third party threats to pipelines and for pinpointing their locations. PIGPEN relies on "smart" sensors that can distinguish between potential pipeline threats and background noise. It will also distinguish between various types of excavation equipment. As a result, PIGPEN will warn the gas system operator of both an impending threat and the nature of the threat.
(iv) GASNET – A sensor network for the real-time monitoring of a pipeline network, transmitting information wirelessly through the pipes. Provides gas distribution operators the ability to (a) detect certain types of third party damage, (b) detect leaks and liquids, (c) enhance the accuracy of virtual models used for gas system analysis, and (d) acquire improved and cost effective system monitoring and control.

3 American Gas Association Research and Development Projects

American Gas Association (AGA) R&D Projects applicable to gas distribution safety are briefly described below. The projects are concentrated in the areas of preventing third party damage, detecting pipe anomalies and assessing the integrity of pipe, improving accuracy and efficiency of current technologies for locating buried pipelines, leak detection and notification technology, and improved coating and pipe repair systems.

Research Priority and Research to Address Priority	Research Issues	Benefits of the Research
Prevention	**Research to prevent 3rd party damage, corrosion, and critical pipe strains. Research to improve CP system and coating effectiveness**	**Reduction in incidents. Reduced O&M costs.**
Preventing 3rd Party Damage	Automated techniques & alternative practices for prevention of outside force impacts to pipelines. Equipment and algorithms to detect unauthorized construction equipment in pipeline ROW.	Alert operators of imminent harm and reduce the number of incidents
Proactive Sensing Systems	Seismic and fiber optic systems to monitor and signal about potential encroachment before damage occur	Preventing threat and impending threats by detecting and pinpointing sources of third party activity
Improve cathodic protection (CP) system effectiveness	Improved monitoring electrodes, buried coupons, or techniques at above ground test stations for CP monitoring. Establish CP anode performance selection criteria. Establish criteria and techniques for effective CP in high resistivity soils and for pipe with degraded coatings. Improved designs for effective CP systems.	Improved CP monitoring performance. Reduced CP O&M costs. Reduce excavations. Fewer repairs
Prevention of critical pipeline strains	Design and assessment tools for the safe and reliable operation of new and in-service pipelines.	Reduced design and mitigation requirements
Determination of maximum safe surface loads	Determine the maximum safe surface and sub-surface loads on buried pipe with known cover and soil conditions. Physical testing databases to characterize surface and blast loadings on buried pipelines. Evaluation of the effects of static and cyclic surface and blast loadings on pre-1970 welds and pipe with non-perforated pipe wall defects.	Reduced design, mitigation, and repair requirements. Better assurance of the safety of existing systems following incidents. Physical testing databases for surface loading and pipe stress model developments. Method for predicting the maximum safe loads on pre-1970 welds.
Improved pipeline coating materials	New and improved pipeline coating materials, such as coatings that are more resistant to defects and "self heal" small defects.	Reduced maintenance costs.
Integrity Assessment	**Research that will improve an operator's ability to identify pipe anomalies and assess the integrity of a pipelines**	**Improved anomaly detection and assessment capabilities, reduced incidents.**
Novel tools to detect corrosion on shielded pipe	A tool that will accurately detect metal loss on shielded pipe. In-ditch methods for corrosion detection and accurate sizing.	Ability to detect disbonded coatings from above ground. Reduce excavations. Fewer repairs via more accurate sizing of defects
Real time sensors to evaluate distribution pipe conditions	Sensors that will provide real time information on the condition of the pipeline, such as corrosion, outside force damage, coating disbondment, etc	Quick assessment of pipe conditions, reduced incidents, reduced O&M cost over time
Cast iron monitoring and risk management software	Technology that will allow an operator to monitor the condition of a cast iron pipeline segment. Risk management software that will allow an operator to better determine when a cast iron system must be repaired or replaced.	Improved integrity of cast iron pipe systems
Development of a Cast Iron Graphitization Meter	A meter that quantifies cast iron graphitization	To prove integrity of cast iron pipe
GPS for an operation and maintenance tracking database	Develop methods to record accurate infrastructure location data during survey, repair, and construction activities.	Provide accurate location data on infrastructure to assist in rapid locating for emergency response and maintenance activities. This will also provide a database to help prevent third party damage.
Inspection of Mains via Access through Services	Innovative methods for insertion or launching of inspection platforms through the gas service	Simplify inspection process, reduce costs associated with introduction of inspection platforms
Pipe Location	**Research to improve the accuracy, efficiency, and cost of current technologies for locating buried pipelines**	**Reduced O&M costs. Reduced excavation incidents. Improved pipe location accuracy.**
Hand held pipe detector	Develop a hand-held detector to locate buried pipes based on pulse-echo technology, with an emphasis on detecting PE pipe. Device should be low-cost, durable, and not require coupling to the pipe or ground	Reduce expenses associated with pipe location. Real-time location of underground facilities in any area including over curbs and hard-to-reach areas. Major advantage is ability to gain wide distribution not just among utilities but among construction companies; increasing safety, reducing costs
Integration of electromagnetic and acoustic obstacle detection systems	Research to integrate electromagnetic and acoustic obstacle detection systems. Integrate drill-head mounted electromagnetic and surface acoustic systems for obstacle detection and avoidance during horizontal directional drilling.	Improved pipe location equipment. Reduce piping installation costs. Prevent damage to underground infrastructure. Maintain horizontal directional drilling as an economic option for piping installation.
Commercialize obstacle detection system using ground penetrating radar	Commercialize GPR mounted on drill head for obstacle detection during horizontal directional drilling	Reduce piping installation costs. Prevent damage to underground infrastructure. Maintain horizontal directional drilling as an economic option for piping installation.
Buried pipe imaging using capacitive tomography	Develop subsurface imaging capability for PE pipe that is lower in cost and easier to use than existing methods.	Reduce cost and ease operation of locating buried PE pipe to facility techniques that require accurate infrastructure locating such as keyhole operations.
Metallic Pipe Joint Locator	Develop system that can detect joints in buried metallic piping.	Excavating & filling one hole is estimated at $1000 to $5000. This system would provide locating accuracy to reduce number of holes needed for joint location, inspection & repair.
Cast Iron Joint and Pipe Locator	Develop a combination tool which can locate underground facilities as well as cast iron joints	Reduce O & M costs particularly for companies who dig test holes to locates pipes and/or cast iron joints
Leak Detection	Improve ability to pinpoint leaks. Decrease leak detection time and cost. Increase convenience of detecting leaks.	Decreased leak detection cost and time to detect. Enhanced ability to detect natural gas leaks.

Leak detection and notification	Prevention of operator error and early-automated detection and notification. More accurate and cost effective leak detection equipment.	Early leak detection and reduced mitigation costs
Miniature ethane/ methane detector for leak survey	Develop hand-held technology for gas leak surveys.	Ability to locate leakage and detect both ethane and methane to differentiate the source of the gas (natural gas vs. swamp gas).
Remote laser leak survey – stationary applications and mobile platforms	A laser survey that can remotely detect leaks, including leaks within buildings	Provide ability to perform survey with less labor expense and in an environment outside the gas plume.
Portable methane detector improvements and field evaluations	Develop a portable detector based on new technology to reduce number of instruments and routine maintenance costs.	By combining the sample requirements into fewer instruments and reducing the routine maintenance and calibration, costs will be reduced.
Evaluation of Aerial Survey Technologies (3000’ and 1000’ elevation)	Aircraft operators who perform aerial surveillance for transmission pipeline companies are claiming their technologies can be applied at lower elevations to provide leak surveillance for distribution companies	Improved Productivity; large service area covered at lower cost
Repair and Rehabilitation	**Research to improve pipe coating repair and repair system. Techniques for the reinforcement of existing pipe. Cast iron repair & replacement strategies**	**New and improved pipeline repair materials. Options for cast iron repair and replacement. Pipeline reinforcement technologies**
Improved coating repair and repair system	New and improved pipeline repair materials. Determine effect of surface preparation and condensation on the adhesion of repair coatings in a ditch. Develop updated coating repair practice	Minimize the need to re-excavate a repair coating from prior mitigation efforts. Reduced maintenance costs
Cast iron repair & replacement strategies.	Research to assess commercially available options for cast iron repair and replacement.	Options for cast iron repair and replacement.
Reinforcement technologies	Techniques to reinforce existing pipe, such as liners, to improve the structural integrity of the pipeline	Improved pipe integrity

Exhibit F

Task 6 Report - Identify Performance Measures

I Performance Measures – National Level

The Risk Control Practices Work Group (RCP) considered what national level performance measures could be used to evaluate the overall effectiveness and performance of distribution integrity management program requirements and practices from a high level, industry-wide perspective. An additional consideration was whether the data would also aid PHMSA in preparing future reports to Congress and other stakeholders.

1 Existing Data Sources

RCP considered performance measures that could be derived from information that is already being reported to PHMSA in gas Distribution System Incident Report (Form PHMSA F 7100.1) and Distribution System Annual Report (Form PHMSA F 7100.1-1) forms.

(a) Incident Data – Incidents per miles of distribution pipe and/or by number of services

Incidents that reach the criteria of 49 CFR 191.3 are reported to PHMSA. These reports have been widely used in various evaluations of pipeline safety. However, recent efforts have been made to compare the number of reportable incidents on distribution lines versus transmission pipelines. This as an inappropriate comparison since there are many more miles of distribution line than transmission line. If it is appropriate to compare distribution and transmission systems, than it would be necessary to normalize the data for miles of pipe.

As for a national measure of distribution integrity management, the number and trends in incident data – especially in terms of incidents per miles of distribution pipe and/or by number of services – would be a reasonable performance measure. Since the number of incidents reported annually is small, minor fluctuations may appear which may or may not be statistically significant. Therefore the data should be utilized only in proper context.

Transmission pipelines are largely in rural areas, where a breach of integrity may pose little danger to persons or property, while distribution lines are typically located in urban areas in close proximity to persons and property. Therefore, an integrity breach in distribution piping could have a higher probability of becoming an incident. Comparisons of lines in similar environments (Class Locations) might be of value, but the data needed to make such an analysis is not currently reported and could be burdensome to begin reporting. Also, the relatively small amount of transmission pipeline in developed areas might make the validity of such comparisons questionable.

(b) Types and amounts of pipe in service – amounts and ratios of amounts

Distribution systems contain pipe of many different materials and sizes, installed over the course of many years. Operator annual reports to PHMSA contain considerable information on the types and sizes of pipe in service.

Today, pipe installed is almost exclusively polyethylene or cathodically protected steel. This is considered "state-of-the-art" pipe. Existing systems may also include types of pipe that are no longer normally being installed in gas systems (cast iron, bare steel, certain types of plastic) and that are not state-of-the-art. Distribution integrity management programs are likely to place increased emphasis on identifying types of pipe that pose a higher risk, and that replacement will be a common risk control measure. Therefore, the amount and ratio of state-of-the-art pipe in service would be a reasonable national performance measure.

A measure that might be considered a reasonable performance measure at the national, or "macro," level, may not be appropriate at the local, or "micro," level. Cast iron pipe may be considered non-state-of-the-art, but individual installations, especially of larger diameter and heavier wall pipe, may be perfectly capable of continuing to provide service of high integrity. In this example, the annual report data would allow tracking of cast iron pipe in service by size. Conversely, while polyethylene pipe is considered state-of-the-art, the term includes certain older vintages with troubled performance histories, and which cannot be separated from the totals in annual report data. When the data on the types of pipe in service is aggregated at the national level, the results should produce a valid national measurement of distribution integrity management.

(c) Age of pipe

PHMSA annual distribution reports include data on the age of pipe in service. This data is not broken down by pipe type or size. The age of pipe by itself is not a meaningful indication of integrity, even at the macro level; simply because pipe is old does not mean it is at risk. Therefore pipe age should not be a national level performance measure.

(d) Number and causes of leaks – totals and by ratio to pipe miles or number of services

PHMSA annual distribution reports contain data on the number of leaks eliminated/repaired during the year, the cause of the leaks, and whether they were on mains or services. RCP could not reach consensus on whether meaningful performance measures could be extracted from that data. A summary of the two positions are discussed below.

(i) Reasons why the number and causes of leaks is a valid national level performance measure:

(A) Incidents typically result from the unintended release of gas – a leak. The frequency of leaks is an indicator of the integrity of the nation's natural gas distribution systems, and the causes are an indicator of threat priority. Leaks and their causes are a specified performance measure in ANSI B31.8S, Section 9.4.

(B) Even if, arguendo, leaks are not a technically valid measure, the public equates leaks with integrity. Failure to include leak numbers and causes as a performance measure might not be credible to some stakeholders.
(C) This measure would utilize data already filed in annual reports, and would place no new reporting burdens on operators.
(D) To the extent leak information is not consistently reported, this is a reason using it to make comparisons between operators would not be valid. But when leak data is aggregated at the national level, so long as individual operators consistently report in a certain way, any differences become irrelevant.
(E) Leak data would be a better indicator of risk if the number of potentially hazardous leaks were reported, instead of numbers that include all leaks whether they posed a hazard to the public or not. But reporting hazardous leaks separately would impose a new reporting requirement and would require regulatory imposition of a national leak classification system, which some proponents are not prepared to recommend.

(ii) Reasons why the number and causes of leaks is a not valid national level performance measure

(A) The vast majority of leaks is discovered through routine operations and are repaired or eliminated without threat to the public by effective leak management programs. Since most leaks are not hazardous, leak numbers are not an indicator of risk or threat to the public. Very few distribution leaks, which are routinely detected by the public and gas distribution operators; result in an incident. They are mitigated by effective leak management programs prior to incidents occurring.
(B) Review of data on the number of hazardous leaks might have some merit, but the number of leaks reported irrespective of hazard does not. Current data does not indicate the hazard of leaks repaired, nor is there a consistent national standard for grading leaks.
(C) The number of leaks eliminated by pipeline replacement is not consistently reported by operators. Some may count a replacement project as zero or one repair, others may report the number of all known leaks thus eliminated.
(D) Leak number data could be misinterpreted. An increase in leaks repaired or eliminated, whether all leaks or only hazardous leaks, could raise concern that gas system integrity is decreasing, but it may mean operators are more aggressively finding and responding to leaks – it may actually be a positive safety indicator. A decrease in the number of leaks could mean replacement programs have eliminated a number of leaks, but it is possible that were never hazardous. In either case, concern could be raised where none is warranted.
(E) Data related to the cause of incidents is not consistent with the data related to the cause of leaks.

(e) Leaks scheduled for repair at the end of the year

A discussion on this reporting category would be similar to that for Number and causes of leaks ((d), above). However, with rare exception, all these leaks would be nonhazardous since they are not being “repaired promptly” (49 CFR 192.703). Many would be low hazard and monitored, perhaps for years, under leak management programs designed to ensure they did not become hazardous. When repaired, these leaks would be captured in later annual reports as repaired leaks and with causal information. Therefore leaks scheduled for repair at the end of the year should not be a national level performance measure.

(f) Unaccounted-for Gas

To persons unfamiliar with gas system operation, the unaccounted-for gas figure might be regarded as an indicator of system leakage and therefore system integrity. But unaccounted-for gas includes measurement and accounting errors unrelated to leakage or integrity (as discussed at page 6-1 of the AGF Study). Therefore, unaccounted-for gas would not be a valid national level performance measure.

(g) Safety-related condition reports

Very few safety-related condition reports are filed. Thus, no meaningful performance measure could be derived from such a limited database.

2 New Data Sources

Based on the Report to Congress,[42] the following elements are expect to be included in a high level, risk-based, performance-oriented Federal regulation of distribution integrity management. Performance measures relative to those elements are discussed below.

1. The operator shall develop a program plan that describes how it manages the integrity of its distribution system, focusing on how it will satisfy the requirements below.
2. The operator shall identify threats applicable to its system.
3. The operator shall characterize the relative significance of applicable threats to its piping system.
4. The operator shall identify and implement appropriate practices (or modify current practices) to prevent, and mitigate the risk from applicable threats consistent with the significance of these threats.
5. The operator shall develop and monitor performance measures to allow it to evaluate the effectiveness of improvements implemented.
6. The operator shall periodically evaluate the effectiveness of its program and make adjustments dictated by its evaluation.
7. The operator shall periodically report to the jurisdictional regulatory authority a select set of performance measures.

(a) Compliance Progress

The Federal regulation may have timetables and deadlines associated with these elements. If operators reported their progress on achieving the levels of plan development and implementation described above, the information could be compiled to measure the progress of

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[42] "Assuring the Integrity of Gas Distribution Pipeline Systems," Report to the Congress, May 2005, Submitted by Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, p. 24.

distribution integrity management program activities at the national level and therefore be a valid national performance measure. However, since the requirement of Element 4 is to "identify" and "implement," progress reporting on this element should be divided into two parts.

There was consideration of state pipeline safety agencies compiling these progress reports should be compiled. While this might provide a more consistent and independent evaluation of the state of operator activities, this would require a state agency to evaluate the progress of each operator every year (or other reporting period). Since most states do not inspect each operator annually, this would require additional inspections and reviews, which would be in addition to the newly added workload on States due to Operator Qualification, transmission integrity management, and possibly public awareness programs. It was concluded it would be much more efficient and less burdensome to have the operators report their progress. To the extent oversight or verification of those submissions is warranted, that could be accomplished through periodic reviews by the states in accordance with their inspection policies.

(b) Confirmation of Periodic Evaluation

The sixth program element regarding periodically evaluation calls for periodic evaluation, and adjustments if necessary, of an operator's distribution integrity management program. Documenting the level of operator compliance with this element is not likely to provide a useful national level performance measure. Verification of periodic evaluation would occur during state regulatory agency inspection to review the distribution integrity management program of the operator.

(c) Reporting of Performance Measures

Company-specific performance measures will be used by operators to measure the effectiveness of their integrity management programs. However, reporting of the individual performance measures would not be useful in determining a national level performance measure since it is anticipated that there will not be a uniform set of individual performance measures for distribution integrity management.

(d) Identified Threat Categories

Since each operator will have to identify the threats applicable to its system and prioritize those threats, a list of the highest ranked company-specific threats could be compiled. However, the value of such a list is questionable. First, excavation damage is expected to be at or near the top of almost all lists. Also, larger operators may have different threats and threat priorities in different segments in different areas of their service territory, and this might not be captured in a report on aggregated company-wide threats. Therefore, a compilation of identified threats was judged not to be of value as a national level performance measure.

(e) Risk Control Practices

Consideration was given to having operators report the risk control practices they use to address threats. One reservation about reporting this data is that it might not be filed in a consistent manner and that the results would be difficult to express numerically. Operators are expected to adopt a wide range of risk control practices tailored to their unique circumstances and resources. Any attempt at a listing of risk control options is likely to be incomplete and might discourage innovation.

Having concluded that, should such a requirement be implemented, an operator should not be expected to "find" some number of specific threats requiring extraordinary risk control practices. If an operator has not identified any threats that require a response beyond its normal practices, "None" should be an acceptable response.

(f) Effective Leak Management

The Risk Control Practices Work Group developed an effective leaks management program outline known as LEAKS as Part of Task 3. If PHMSA adopts this or a similar concept in regulation, a required filing by operators on their progress in developing and implementing such a leak management program could be used to develop a national performance measure.

(g) Hazardous Leaks

In the discussion of whether leaks should be used as a performance measure, it was suggested that a listing of hazardous leaks repaired (by category) would be a better indicator of integrity than a listing of all leaks regardless of hazard. However, there is currently no universally accepted definition or consensus on what constitutes a hazardous leak. Therefore any attempt to collect data on hazardous leaks would require a regulatory definition or criteria be imposed. But the results of doing so could include operators adopting the new definition and thereby losing continuity with past leak records, or being forced to keep two sets of books on leaks. While merit was seen in the concept, implementation would be difficult and potentially contentious. We did not reach closure on this issue.

3 Caution

It must be emphasized that reported data should not be used to rank operators or to make comparisons between them. Each operator will have a unique combination of facilities by type, age, and operating history, as well as geographical and environmental circumstances. The differences between operators can make comparisons meaningless and irrelevant.

II Internal Performance Measures – Company

Internal performance measures are company specific and represent data a company could use to evaluate the performance of the risk control practices initiated under its distribution integrity management program. This data would be derived from internal company records and information not provided in a required or public report, although the data and analysis would be available to regulators during inspections.

When developing performance measures, the following guidelines should be considered:

1. Performance measures should reflect the purpose of the distribution integrity program or specific risk control practice.
2. Performance measures should be something that can be counted, graphed and validated.
3. It is best to select "a critical few" measurements. "There are decreasing returns as measurements are added, and too many measurements can overwhelm the measurement system."[43]
4. Just as each operator must evaluate its system and determine which threats are applicable to that system, so too, each operator must develop performance measures that match the specific risk control practices of their distribution integrity program.

A listing of possible company specific performance measures that an operator may use for its distribution integrity management program has been developed. In using the table, it is important to consider the following:

1. These are broad general categories of performance measures – a more detailed breakdown may be necessary for effective results. For example, material failures may need to be categorized by specific pipe type, age or manufacturer to zero in on the root cause of such failures.
2. This list is not intended to be all-inclusive, nor is it intended that operators should be expected to use each listed metric.
3. "Number" may be expressed as a percentage, as per/mile or per/service, or any other numerical expression that makes the data meaningful.
4. The emphasis in this table is on metrics that can be expressed numerically. However, non-numeric methods should not be ignored. For example, anecdotal statements from field personnel can be an important source of information on sources and root causes of threats, and useful to validate or challenge what numerical data is indicating.

Possible performance metric options for the identified distribution threats are:

(a) Corrosion

1. Number of corrosion leaks
2. Number of exposed pipe condition reports that found corrosion or coating damage
3. Number of repairs required due to non-leaking pitting or coating damage (above and below ground)
4. Number of cathodic protection zones found with low protection levels
5. Number of areas of active corrosion found (unprotected pipe)

(b) Natural Forces

1. Number of leaks due to weather or other natural forces
2. Number of repair, replacement or relocation actions due to natural forces

(c) Excavation

1. See report of the Excavation Damage Work Group.

(d) Other Outside Force Damage

1. Number of leaks or failures caused, or repairs necessitated, by vandalism

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[43] Page 9.8, Juran's Quality Handbook, Fifth Edition, McGraw-Hill, New York, 1999

2. Number of leaks or failures caused, or repairs necessitated, by vehicular damage
3. Number of instances of damage due to fire or explosion.
4. Number of leaks or failures on previously damaged pipe

(e) Material or Joints

1. Number of pressure test pipe failures
2. Number of pressure test joint failures
3. Number of in-service pipe or joint failures (not caused by outside force or excavation damage)
4. Number of production joints rejected by an inspector other than the joiner
5. Number of joiners failing requalification tests

(f) Equipment

1. Number of regulator failures
2. Number of relief valve failures
3. Number of seal, gasket or o-ring failures
4. Number of regulators or relief valves found with set points outside of acceptable range
5. Number of emergency valves found inoperable or inaccessible
6. Number of pressure recorders found inoperable or inaccurate
7. Number of SCADA failures, system upsets or false readings

(g) Operations

1. Number of service outages due to operator error
2. Number of inspections or tests required by regulations not completed on time or as required
3. Number of persons failing re-qualification tests
4. Number of odor tests finding insufficient odorant
5. Number of response times to leak or odor calls not within regulatory or operator time limits
6. Number of hazardous leaks not repaired within regulatory or operator lime limits

(h) Other

1. Case-by-case determination

Attachment C

Integrity Management for Gas Distribution Pipelines

Excavation Damage Prevention Working Group Report

October 24, 2005

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Acronyms

AGA – American Gas Association
APGA – American Public Gas Association
API – American Petroleum Institute
AGF – American Gas Foundation
CD – Compact Disc
CFR – Code of Federal Regulations
CGA – Common Ground Alliance
DOT – Department of Transportation
EDPG – Excavation Damage Prevention Group
EFV – Excess Flow Valve
FCC – Federal Communications Commission
NAPSR – National Association of Pipeline Safety Representatives
NARUC – National Association of Regulatory Utility Commissioners
OQ – Operator Qualification
PHMSA – Pipeline and Hazardous Materials Safety Administration
QC – Quality Control
RP – Recommended Practice
USC – United States Code

Executive Summary

This report provides the findings and conclusions of the Excavation Damage Prevention Group (EDPG), one of four work/study groups organized by the U. S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA), in early 2005, to identify opportunities to enhance natural gas pipeline safety. Specifically, the EDPG was tasked with considering actions, approaches and opportunities to help significantly reduce excavation damage to pipeline facilities.

Summary of Key Findings

1. Excavation damage poses by far the single greatest threat to distribution system safety, reliability and integrity; therefore excavation damage prevention presents the most significant opportunity for distribution pipeline safety improvements.
2. States with comprehensive damage prevention programs that include effective enforcement have a substantially lower probability of excavation damage to pipeline facilities than states that do not. The lower probability of excavation damage translates to a substantially lower risk of serious incidents and consequences resulting from excavation damage to pipelines.
3. A comprehensive damage prevention program requires nine important elements be present and functional for the program to be effective.
4. Federal Legislation is needed to support the development and implementation of damage prevention programs that include effective enforcement as a part of the state's pipeline safety program. This is consistent with the objectives of the state pipeline safety programs which are to ensure the safety of the public by addressing threats to the distribution infrastructure. The legislation will not be effective unless it includes provisions for ongoing funding such as federal grants to support these efforts. This funding is intended to be in addition to, and independent of, existing federal funding of state pipeline safety programs.

Distribution Safety Studies

Excavation damage has long been recognized as the single greatest threat to the safety of the natural gas distribution infrastructure. A study completed in early 2005 by the American Gas Foundation[44] (AGF) for the gas industry found that nearly 35 percent of serious incidents (involving injuries or fatalities) during the study period were due to

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[44] American Gas Foundation, Safety Performance and Integrity of the Natural Gas Distribution Infrastructure. January 2005, Washington, DC.

third-party damage[45]. A parallel study conducted by Allegro Energy Consulting[46] for the PHMSA in early 2005 concluded that 38 percent of the total natural gas incidents over the study period were caused by excavation and mechanical damage, with 91 percent of these attributed to third-party activities. The Allegro study also found that the next leading contributor, causing 11 percent of serious pipeline incidents during the study period, was vehicle-related incidents involving pipeline facilities. By comparison, corrosion accounted for only 3 percent of the incidents.

Based on the results of these studies, it follows that improvements in excavation damage prevention programs provide the greatest opportunity for distribution pipeline safety enhancements.

EDPG Analysis

The EDPG reviewed and analyzed data from DOT annual reports, state one-call statistics, damage prevention Best Practices from the Common Ground Alliance (CGA), distribution pipeline operator practices submitted by the American Gas Association (AGA), and other available data. The purpose of this review was to determine if there are existing actions, approaches or practices that could be applied on a broad scale to significantly reduce the number of excavation damages.

In analyzing the available data, a specific emphasis was placed on comparing the damage performance of states that have comprehensive damage prevention programs with effective enforcement, to states that do not have all of the elements of an effective damage prevention program. The purpose of this focus was to determine if there is a corresponding reduction in damages and, therefore, an improvement in distribution pipeline safety in those states.

Findings and Conclusions

The EDPG's findings and conclusions are as follows:

1. Excavation damage poses by far the most significant threat to the safety and integrity of the natural gas distribution pipeline system. Therefore, excavation damage prevention presents the greatest opportunity for gas distribution system safety improvements.

2. Distribution pipeline safety and excavation damage prevention are intrinsically linked. Any effort to improve distribution pipeline safety is meaningless if it does not seriously address the threat of excavation damage prevention.

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[45] See definition on page 26 of this report.

[46] Allegro Energy Consulting, Safety Incidents on Natural Gas Distribution Systems: Understanding the Hazards, February 2005, New York, NY.

3. Although distribution pipeline operators are required to have damage prevention programs under 49 CFR Part 192, preventing excavation damage to pipelines is not completely under the control of operators.

4. Many states do not have comprehensive damage prevention programs including effective enforcement authority in spite of repeated attempts to pass effective damage prevention legislation.

5. Industry, regulators, excavators, CGA and One-Call Centers throughout the nation have made significant progress in reducing gas damages during the period from 2000 to 2004. Over this period, national gas distribution damages due to excavation were reduced from 132,478 to 108,577. This reduction of over 18 percent was due principally to efforts by all parties in the areas of training, education and Operator Qualification to highlight a few.

6. Separating that reduction in excavation damages from 2000 to 2004 into states identified with comprehensive damage prevention programs (including effective enforcement by the state agency involved in pipeline safety) and those without, the reduction in damages for those with identified comprehensive programs is a reduction of 22.6 percent vs. a reduction in the other states of 17.5 percent.

7. Evaluating those excavation damages on a normalized basis of damages per 1000 tickets, the identified comprehensive damage prevention states had over a 20 percent lower damage rate in 2000 and a 26 percent lower damage rate in 2004 than the remaining states.

Damages/1000 Tickets	**2000**	**2004**
Other States	6.27	4.91
Comprehensive States	4.98	3.64
Percent Reduction	20.6%	25.9%

8. Review of each individual state's data for the five identified with comprehensive damage prevention programs (Connecticut, Georgia, Massachusetts, Minnesota, and Virginia) indicates a significant reduction in damages (30 percent or more) in the years immediately following the implementation of enforcement by the pipeline safety groups in each case.

9. Analysis of five individual states with comprehensive damage prevention programs that include effective enforcement by the state agencies with responsibility for pipeline safety (Connecticut, Georgia, Massachusetts, Minnesota, and Virginia) shows a material improvement in gas distribution excavation damages per 1000 tickets compared to individual states that do not have effective enforcement programs. For example, states with mature damage prevention programs that include enforcement, such as Virginia and Minnesota, have normalized excavation damage rates that are less than half the rates of states without effective enforcement programs.

10. Federal Legislation is needed to support the development and implementation of damage prevention programs that include effective enforcement as a part of the state's pipeline safety program. This is consistent with the objectives of the state pipeline safety programs which are to ensure the safety of the public by addressing threats to the distribution infrastructure. The legislation will not be effective unless it includes provisions for ongoing funding such as federal grants to support these efforts. This funding is intended to be in addition to, and independent of, existing federal funding of state pipeline safety programs.

11. A comprehensive damage prevention program requires nine important elements be present and functional for the program to be effective. These elements are discussed in detail later in the report.

12. Incentives (positive and negative) should be provided to operators, excavators, and locators to ensure compliance with the damage prevention program requirements.

13. Operators should review and implement CGA Best Practices and other industry practices as appropriate to help reduce damages to their facilities. Similarly, other affected stakeholders should review and implement applicable CGA Best Practices.

14. Damage metrics should be provided to the PHMSA by operators as a measure of natural gas distribution pipeline safety. Reportable metrics should include total damages, as defined herein, and normalized damages (damage ratio), defined as damages per 1000 tickets. This may require the revision of 49 CFR Part 191.

15. Operators should track additional damage prevention program metrics for internal use in evaluating the effectiveness of the operator's program.

16. Excess Flow Valves (EFV) are one tool that should be considered by operators to address the consequences associated with excavation damages.

17. All stakeholders must participate in the excavation damage prevention process.

Introduction

In testimony before Congress in July 2004, the Department of Transportation (DOT) Inspector General recommended that the Office of Pipeline Safety define an approach for requiring the operators of natural gas distribution systems to implement some form of integrity management to enhance the safety of these systems. The FY 2005 Conference Committee on Appropriation requested DOT to submit a report detailing the extent to which elements of integrity management plans may be applied to gas distribution pipeline systems to enhance their safety.

In May 2005, the PHMSA submitted a report to Congress which, among other things, discussed the PHMSA's plan to implement a program, jointly with states and other stakeholders, to focus attention on areas that pose the highest risk in gas distribution systems and to more effectively manage these risks. The first phase of the plan involved a comprehensive study of the relevant threats affecting distribution system integrity. PHMSA worked with states' pipeline safety agencies, distribution pipeline operators, representatives of certain associations and the public to conduct this study.

Four working groups were organized to review the existing information, gather additional data, and make technical findings. One of these groups, the Excavation Damage Prevention Group (EDPG), was tasked with considering practices, actions and approaches that have been effective in mitigating excavation damage to pipelines. This report presents the work of the EDPG and its findings.

Study Objectives and Approach

The primary objective of the EDPG was to devise a plan to enhance natural gas distribution pipeline safety by significantly reducing excavation damages. Excavation damage is recognized as the leading cause of gas distribution pipeline incidents.

The approach the EDPG took to achieving this objective was to review and analyze available state-level third-party[47] damage and excavation damage[48] data for gas distribution pipelines. The EDPG solicited data from all 50 states regarding one-call ticket volumes and gathered data from the PHMSA and states regarding numbers of damages to gas distribution pipeline systems. Statistical analyses of these data were performed and the results were demonstrated in a series of charts and graphs to facilitate the discussions and analysis.

The EDPG also looked at information on damage prevention processes, best practices and performance metrics. The American Gas Association (AGA) solicited and shared

47 "Third party" is an outside force damage directly attributed to the striking of gas pipeline facilities by earth moving equipment, other equipment, tools, vehicles, vandalism, etc. Damage is by personnel other than the operator or the contractor working for the operator.

48 "Excavation Damage" is damage caused by earth-moving or other equipment, tools, or vehicles. This includes leaks from damage by operator personnel or an operator's contractor or people not associated with the operator.

information from its members regarding successful damage prevention practices and processes currently being implemented.

The EDPG members discussed the results of the data analyses and the other available information in a series of face-to-face and telephonic meetings. The members reached consensus on all issues and formulated their findings and conclusions that are included in this report.

Team Structure

The EDPG was composed of individual representatives of various damage prevention stakeholder groups. Participating group members included representatives of state and federal pipeline safety regulators, natural gas transmission and distribution pipeline operators, excavators, and the CGA.

The following table identifies the active EDPG participants.

Name	Representing Organization
Massoud Tahamtani (Chair)	Virginia State Corporation Commission and the National Association of Pipeline Safety Representatives (NAPSR)
Jenny Brito[1]	ConEd (AGA)
Dewitt Burdeaux	PHMSA
Bruno Carrara	New Mexico Public Regulation Commission and NAPSR
Mike Jones	Philadelphia Gas Works (APGA, AGA)
Bob Kipp	CGA
Rick Lonn	AGL Resources (AGA)
Mike McGrath	Minnesota Dept. of Public Safety, Office of Pipeline Safety and the National Association of Regulatory Utility Commissioners (NARUC)
Stu Megaw[2]	Associated General Contractors of America (AGC)
Bruce Paskett	NW Natural (AGA)

1 Jenny Brito participated in the EDPG in the place of Frank Ciminiello, ConEd.
2 Stu Megaw participated in the EDPG in the place of Vic Weston, Tri-State Road Boring.

Table 1

Early Conclusions

It is common knowledge amongst pipeline operators as well as state and federal pipeline safety regulators, that excavation damage is the single most significant threat to the safety and integrity of natural gas distribution systems. In fact, a natural gas industry study completed in January 2005 by the American Gas Foundation entitled "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure" found that 46.6 percent of the serious incidents involving injuries or fatalities from 1990-2002 were the result of outside force. Third party damage accounted for 34.6 percent of these serious incidents. In addition, a separate report prepared by Allegro Energy Consulting entitled "Safety Incidents on Natural Gas Distribution Systems: Understanding the Hazards" prepared for PHMSA, noted that 38 percent of natural gas distribution incidents during 1999-2003 were caused by excavation and mechanical damage to pipeline facilities (Figure 1).

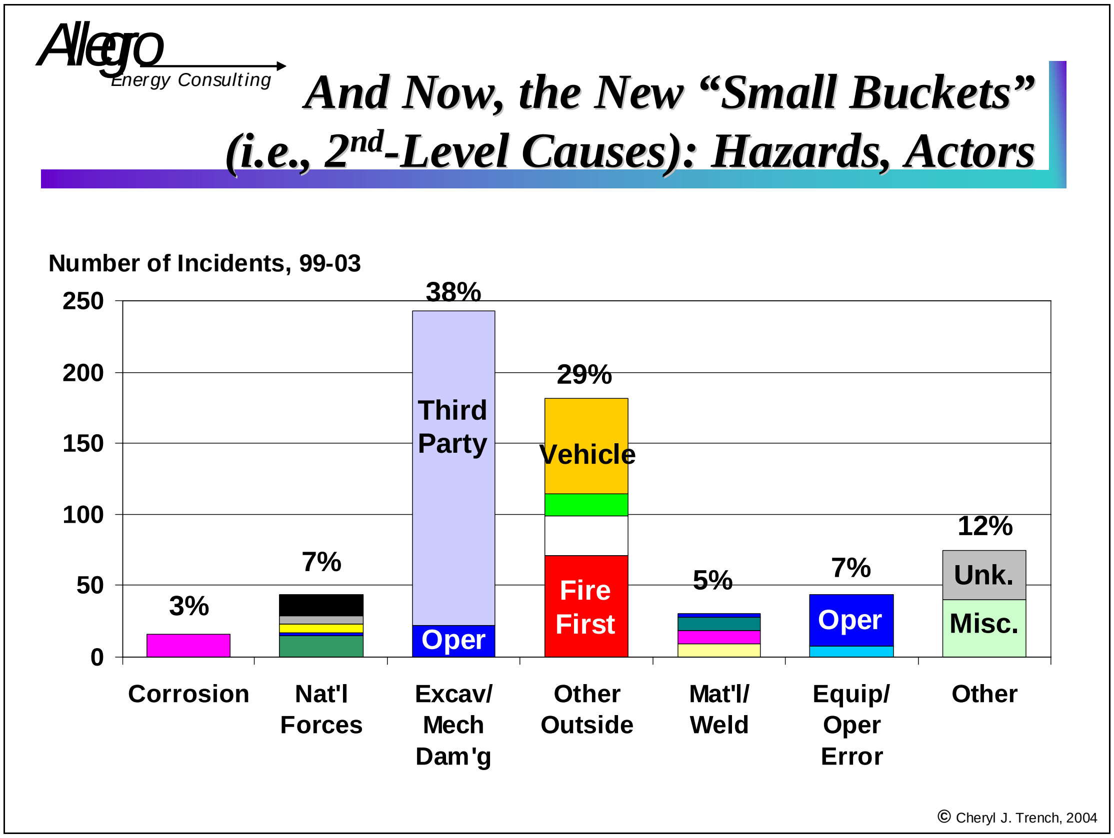


Figure 1

Reducing excavation damage however, is not at all similar to addressing other threats to pipelines. The activity of excavation around underground facilities involves several stakeholders including the excavator, the one-call center, the locator and the operator. The operator may accurately perform all its responsibilities under the applicable laws and regulations and still experience damage to its facilities due to others within the process not performing their responsibilities completely and accurately. Consequently, preventing excavation damage to pipelines is not completely under the control of pipeline operators. All stakeholders involved must do their part to significantly reduce excavation damage to pipelines.

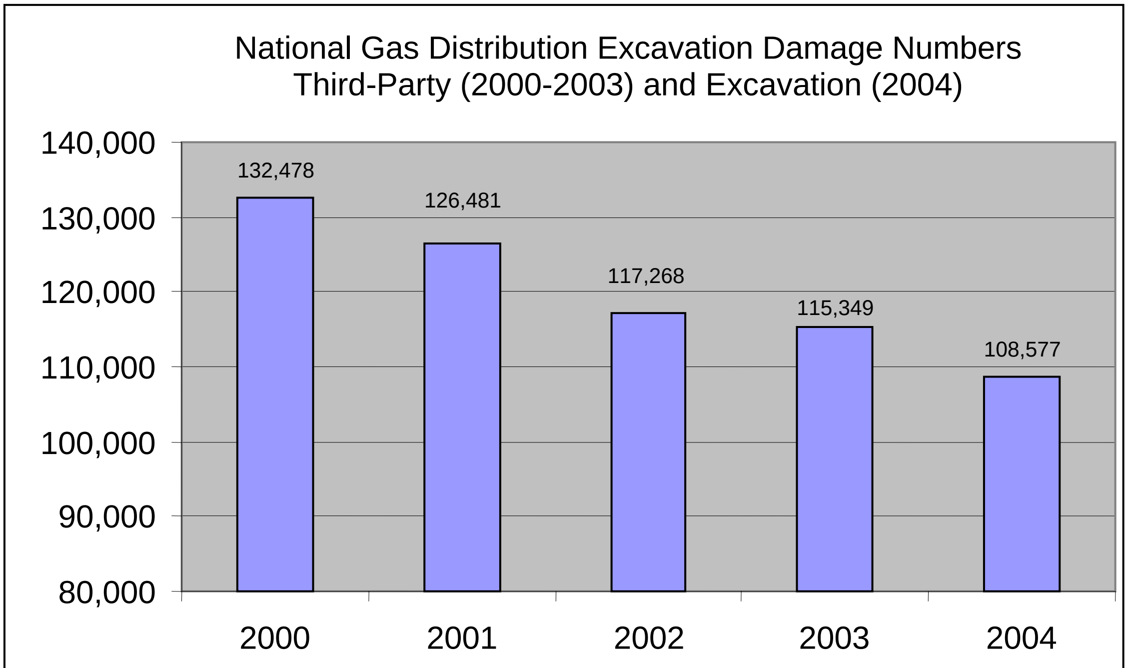
Data Review and Analysis

As stated previously, the approach of the EDPG from an analysis perspective was to review and analyze the best available excavation damage data at a national level for gas distribution systems and wherever possible to compare state-level data. This was done with two tasks in mind:

> First – to identify the national historical trends on excavation damage for the period 2000 through 2004, to answer the question of whether the excavation damage situation in the country is getting better or worse based on the efforts already underway throughout the nation. Those efforts include such things as One Call education, excavator training, Operator Qualification and the efforts of CGA, to name a few.
>
> Second – to analyze the data nationally to determine whether the presence or absence of a comprehensive damage prevention program, including effective enforcement, made an appreciable difference in excavation damage rates of gas distribution systems.

As far as the data used in the analysis, the two components used were the total gas distribution excavation damage numbers by state for the study period, which were provided from DOT annual reporting numbers and then locate ticket volumes by state for that same period which were provided by the various state agencies.

When reviewing the total gas distribution damage numbers for the nation for the period, one can see in Figure 2 that there has been a positive downward trend in gas distribution excavation damages from 132,478 in 2000 to 108,577 in 2004 or over 18 percent reduction. This is an encouraging start.



Source: PHMSA's Annual Report F 7100.1-1

Figure 2

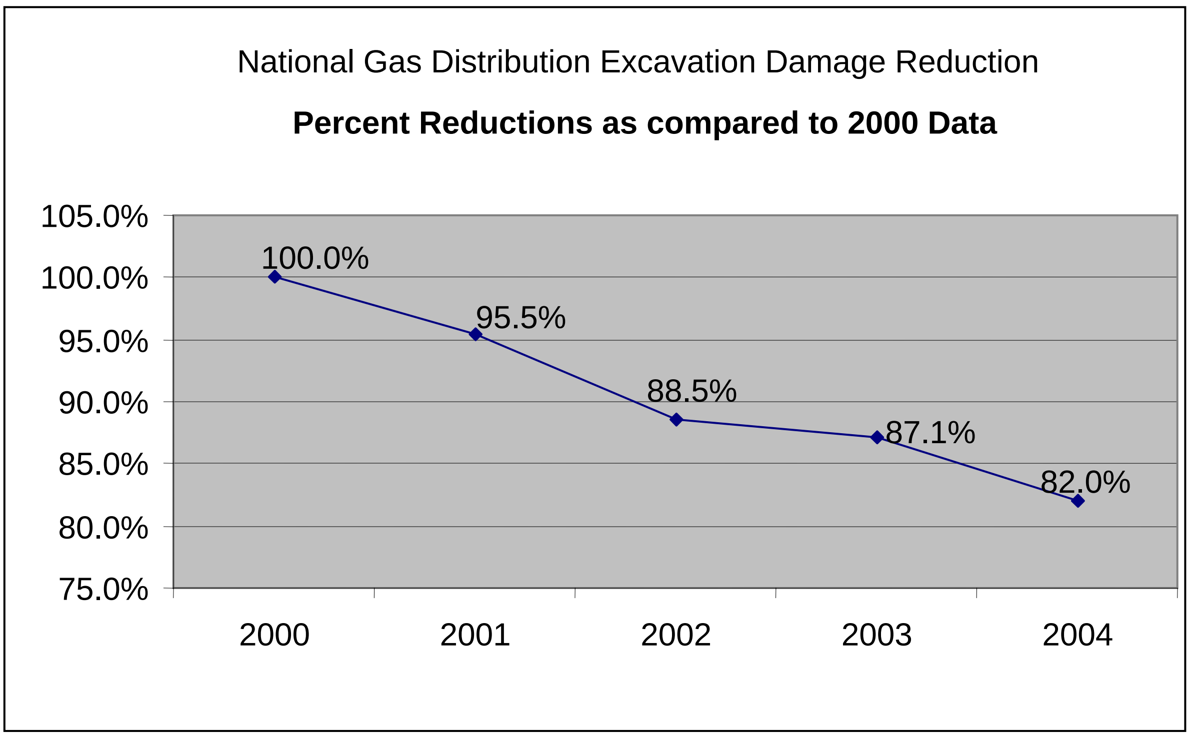


Figure 3

These reductions demonstrate that the current and previous efforts of the operators, excavators, state regulators, federal government, CGA and the One Call Centers over the period 2000 through 2004 in the areas of training, OQ and education have made a positive impact.

As a result, the question that needed to be answered was whether the presence or absence of a comprehensive damage prevention program including effective enforcement made an appreciable difference in the excavation damage rates of gas distribution systems. The EDPG's review of various states' damage prevention programs concluded that effective enforcement was by far the most significant difference between the various state One Call laws and damage prevention programs.

In order to make that determination, the remainder of the analysis required the separation of the state-level data into groups with comprehensive damage prevention programs (including effective enforcement) and those without. The data was then analyzed both from a total damages perspective and from a normalized perspective where the damage data was evaluated based on damages per 1000 tickets to ensure the maximum level of confidence in the results.

In this analysis the various states programs were reviewed and the states of Connecticut, Georgia, Massachusetts, Minnesota and Virginia were identified as having had comprehensive damage prevention programs (including effective enforcement) since 2000 which also had available locate ticket volume data,. For total damage numbers comparison, the five states' data were compared to the data for the remainder states. For the normalized comparisons of damages per 1000 tickets, the five states' data was compared to 34[49] states for which locate ticket volumes were available.

Looking at the national excavation damage percent reduction chart above (Figure 3) and then breaking it out into states with comprehensive damage prevention programs and those without (Figure 4[50], below), one can see that there is a significant difference in damage reductions over each of the years in the study period between these two groups.

[49] Data was requested from all states. States that did not provide data were not included in this analysis.
[50] PHMSA Distribution Pipeline Systems, Annual Report Data, Based on data for all reporting states, PR & DC

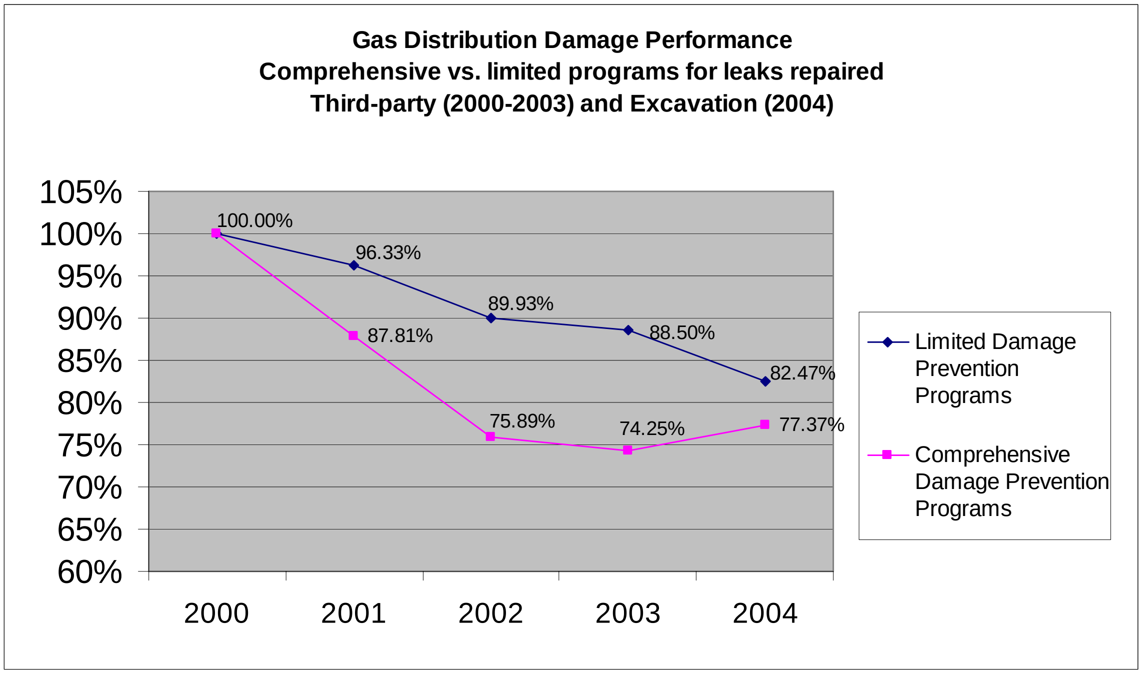


Figure 4

Taking that data and normalizing it based on damages per 1000 tickets brings the trends into even clearer perspective. The data indicates a significant improvement in damage rates for those states with comprehensive damage prevention programs when compared to those without.

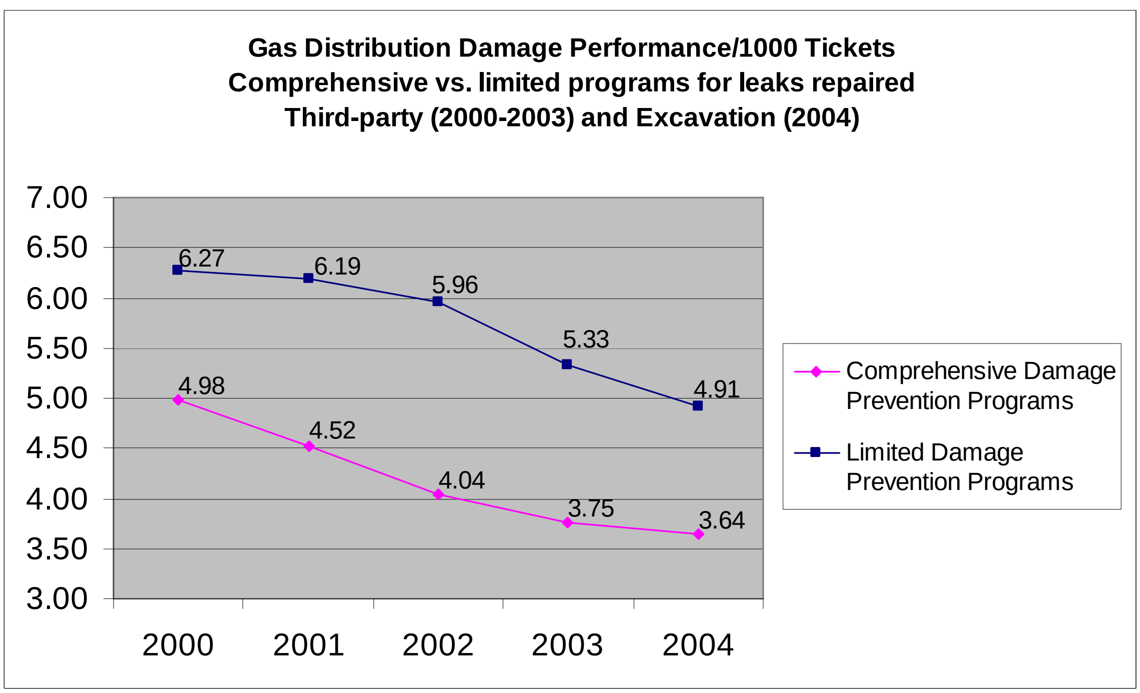


Figure 5

As can be seen in Figure 5, the most recent (2004) damages per 1000 tickets for states with comprehensive damage prevention programs is 3.64 damages per 1000 tickets and for the remaining states[51] is 4.91 damages per 1000 tickets. This comparison shows damage rates in states with comprehensive damage prevention programs is 25.9 percent lower when compared to the remaining states. This is a truly significant reduction in gas distribution damages.

Referring back to Figure 2, one can see that there were 108,577 damages in 2004. Of that total, 98,294 were in states with limited damage prevention programs. By simply applying a 25.9 percent reduction in damages to that total of 98,294 damages, one can see <u>the potential of reducing gas distribution damages by over 25,400 damages per year</u> just by bringing the states without comprehensive damage prevention programs down to the same damage rates as those with comprehensive programs.

Admittedly, such results could not be achieved overnight and in fact would require several years after the implementation of comprehensive damage prevention programs in each individual state. This assessment was based on a review of the historical damage prevention rates for Connecticut, Georgia, Massachusetts, Minnesota and Virginia all the way back to the start of their damage prevention programs compared to the 2000 to 2004 period. In all five cases it is very clear that it took 3 to 5 years to achieve significant benefits from a comprehensive damage prevention program including effective enforcement. This can be seen from a review of damage ratio data for Minnesota and Virginia (Figures 6 and 7).

[51] Limited damage prevention programs' ticket data includes 32 states and D.C.

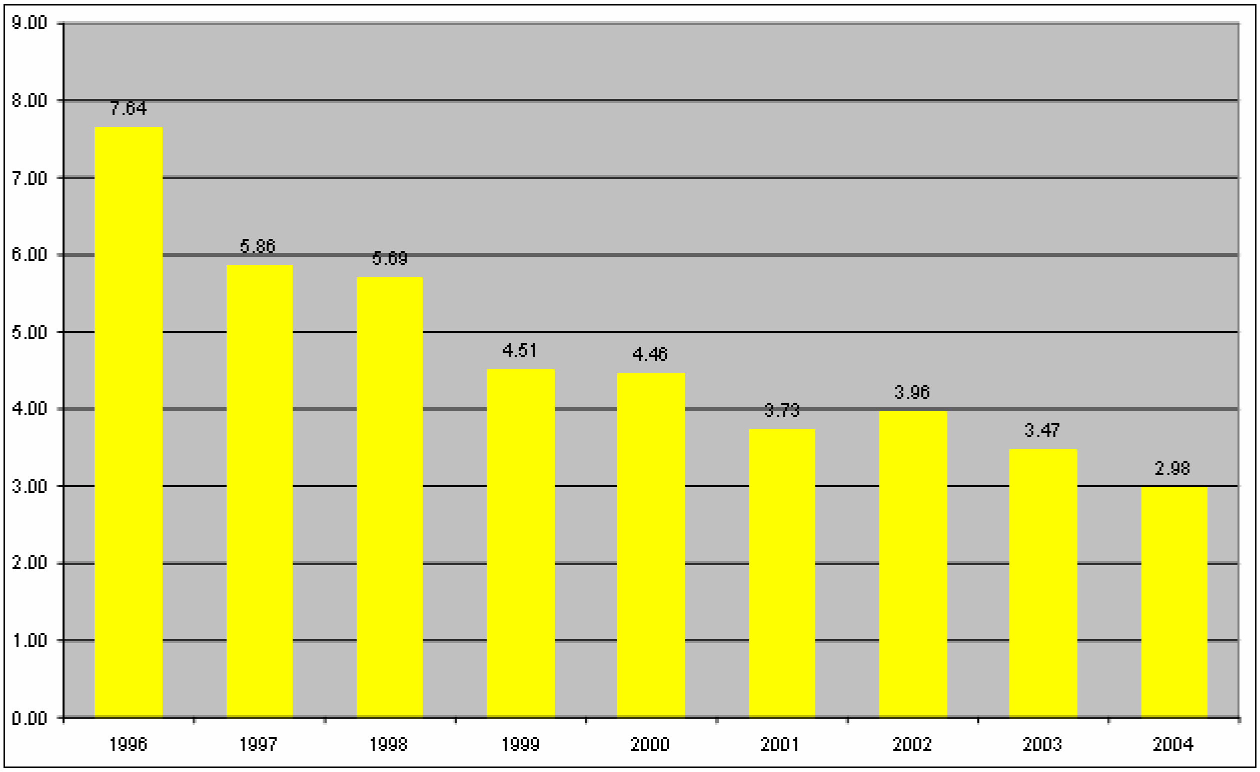


Figure 6: Minnesota Gas Distribution Excavation Damages per 1000 Tickets

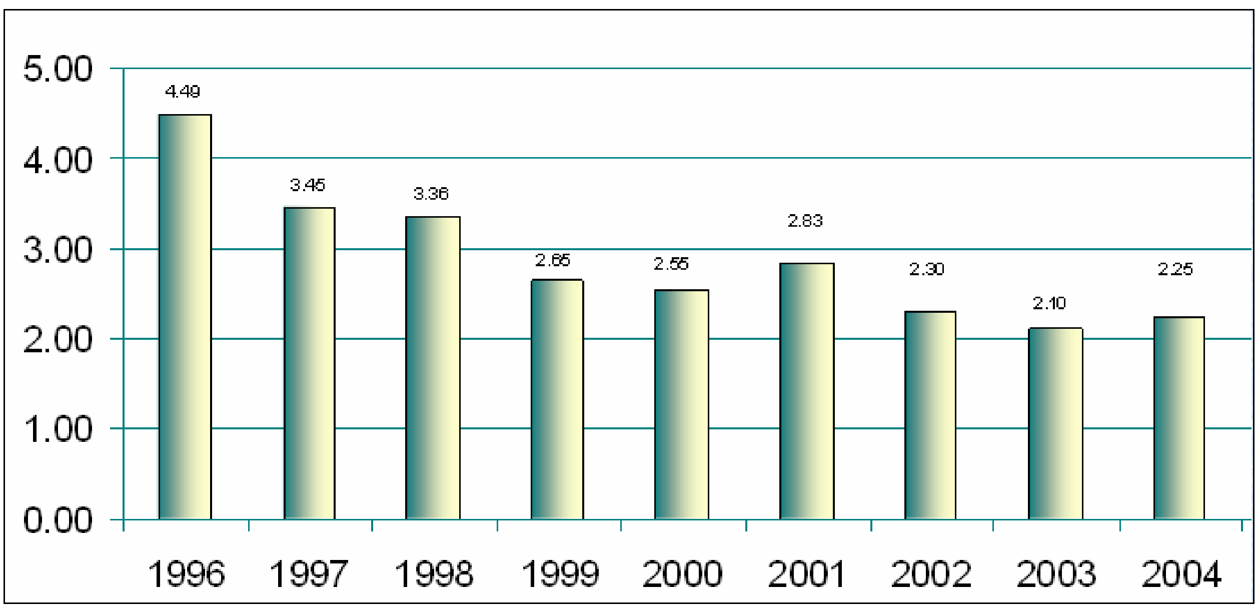


Figure 7: Virginia Gas Distribution Excavation Damages per 1000 Tickets

Findings

Following are the major findings and conclusions offered by the EDPG based on its analysis of data, review of actions, government and industry practices and discussions with stakeholders.

1. Elements of an effective damage prevention program

The EDPG spent a significant amount of time reviewing existing industry and government practices and approaches to prevent or significantly reduce damage to underground facilities. This effort included, but was not limited to, the review of the CGA Best Practices, the review of a number of AGA member operator practices and processes, and the practices of several states' with comprehensive damage prevention programs. As a result, EDPG has concluded that an effective damage prevention program must include the following elements.

- Enhanced communication between operators and excavators

At the heart of any damage prevention program should be the exchange of accurate and timely information between the excavators and operators of underground utility facilities. When an excavator plans to excavate, he/she must accurately capture certain information regarding the project and provide or transmit that information to the one-call center. The receipt of this information by the center marks the point in time from which the center and the operator/locator must accomplish their specific tasks in order to complete the marking of underground facilities before excavation begins. The communication between the excavator, the center, the operator, and the locator continues throughout the life of the project. Obviously, the easier and the more efficient this communication, the more effective the two main stakeholders, the excavators and the operators, can "talk" about the actions of the excavator as they may impact the facilities of the operator. The CGA best practices address many of the elements of this communication process and how it can be improved. A pilot project currently under consideration by PHMSA is to research, develop and implement technologies that appear to have great potential to enhance the communication of accurate information between excavators and operators.

- Fostering support and partnership of all stakeholders in all phases (enforcement, system improvement, etc.) of the program

All stakeholders in the damage prevention process must be partners. The excavators are a critical force within our local, regional and national economy. Similarly, the vast and complicated network of underground utility facilities provides essential services to our homes and supports our economy. Excavators, operators, one-call centers, locators and local, state and federal governments must foster partnership in all phases of the damage prevention process. Two examples may further illustrate this point. In Virginia and several other states, the enforcement of their laws is accomplished through a review of damages/violations by a balanced committee of all stakeholders. The recommendations of the committees are then reviewed by the enforcing agencies. These Committees provide essential expertise and work together with one goal in mind – prevention of damage to facilities. Another example is outreach programs between operators and excavators working around the operators' facilities. This has resulted in the excavator seeking help with locating or other operator related issues by contacting the operator for help at the "eleventh hour" instead of taking a risk excavating and possibly causing damage, injury or death.

- Operator's Use of Performance Measures for Persons Performing Locating of Pipelines and Pipeline Construction

Operators must have a quality assurance program in place to monitor and ensure that the locating and marking of their facilities are properly performed. Operators may complete locates using company personnel, or they may contract with locating companies to locate and mark the operator's facilities in response to notices of excavation. If locating services contracts are used, the contract should include performance measures with incentives and penalties to encourage the contract locator to provide accurate and timely marking of the facilities. CGA Best Practices for Locating and Marking of Facilities, detail the components of an operators' audit of locators work. Operators also contract with utility contractors to construct pipeline facilities. Obviously, these contractors work in close proximity to the operators' facilities. A quality assurance program with performance measures tied to incentives and penalties must also be in place for these contractors to help reduce damage to the operators' facilities by these contractors.

- Partnership in employee training

Effective training of those involved with excavation, the locating of facilities, and the one-call process is imperative in reducing damage to underground facilities. The operators, the one-call center, the enforcing agency and the excavators should partner to design and implement training for operator's, excavator's and locators' employees.

- Partnership in public education

The majority of public education and awareness campaigns are carried out by the one-call centers on behalf of all operators that are members of the center. The gas pipeline operators are required to conduct excavator and public education under 49 C.F.R. §192.614 and §192.616. CGA is promoting a number of best practices for public education. It is a proven fact that partnership by all stakeholders greatly contributes to the effectiveness of a damage prevention public education program.

- Enforcement agencies' role as partner and facilitator to help resolve issues

An active damage prevention program brings about many different issues that must be resolved in a timely manner. The resolutions may involve amending the existing laws, rules, and policies. It may involve use of new technologies or implementation of new training activities. The enforcing agency is best suited to bring the stakeholders together and facilitate productive discussions to resolve the issues. In this process, the agency must be a partner and ensure fairness for all stakeholders.

- Fair and consistent enforcement of the law

The EDPG determined that although many current state damage prevention laws contain enforcement provisions, they may not be effective. States where enforcement of damage prevention laws is conducted by the agency responsible for pipeline safety have shown significant reductions in damages to pipeline facilities. Having recognized this, the EDPG concluded that fair and consistent enforcement is the key to establishing credibility for the enforcement of the program.

- Use of technology to improve all parts of the process

The excavators, one-call centers, operators and locators should use existing and new technologies to improve the communication of accurate and complete information from the excavators to the one-call centers. The one-call center must employ the best technologies available to accurately depict the information received from the excavators on the center's maps and notify member-operators involved. The center must also be able to efficiently receive the operator's responses to the excavator's notices and make available these responses to the excavators. The operators must employ technologies to make available accurate facility maps to their locators. Locators must use the best available technologies to mark the facilities and communicate the marking status to the center.

- Analysis of data to continually evaluate/improve program effectiveness

In order to evaluate the damage prevention program, certain data must be collected and analyzed on a regular basis. The results should be used to improve program areas where necessary. For example, consistent reporting and complete analyses of damage data could show root causes of damage, parties responsible for the damages, and other useful trends. Such analyses can be used to justify amending laws, rules, regulations, procedures. The data can also be used to properly allocate limited educational dollars where they are needed.

2. CGA Best Practices and Operator Processes To Reduce Excavation Damage

The EDPG recognized that the CGA Best Practices, when appropriately applied, should help in efforts to reduce excavation damages. However, the EDPG understands that a "best practice" for some gas pipeline operators may not always be best for others.

AGA identified some work processes and practices that are currently and effectively being implemented by a number of its member operators to reduce damages to their systems. Those work processes and practices are noted below. Some of them may exceed current regulatory requirements and some of them may be consistent with or parallel to current CGA Best Practices.

- Perform trend analysis – Operators should consider performing general trend analysis of damages to help identify areas in need of special attention. Damages can be sorted by geographic location (i.e. county or city), work type, excavator, cause, etc.

  This practice is related to existing CGA Best Practices, particularly: “Data is used to improve damage prevention efforts. The reported data is used to assess and improve underground damage prevention efforts.” (Reporting & Evaluation #16); “Data is summarized by key components.” (Reporting & Evaluation #18).

- Perform root-cause analysis – Operators should consider performing a detailed root cause analysis on damages resulting in severe consequences.

  This practice is related to existing CGA Best Practices, particularly: “A damaged facility is investigated as soon as possible after occurrence of damage. Anytime damage occurs, a proper investigation is performed. This is to determine not only the responsible party, but also the root cause of the damage. The information gathered from damage investigations is essential in preventing future damages.” (Locating & Marking #16); “Root causes of damages or near damages are identified.” (Reporting & Evaluation #19).

- Maintain accurate records and maps – Operators should provide locators with access to accurate system records and establish a process to update maps accordingly.

  This practice is related to existing CGA Best Practices, particularly: “Locators use maps to assist in finding the excavation site and to assist in determining the general location of the buried facility. The locator provides precise facility location to the facility owner/operator when there is a discrepancy. The locator provides to the facility owner/operator the most precise facility location information obtained from a locate when there is a discrepancy.” (Mapping #8); “The facility owner/operator provides mapping data access. The facility owner/operator provides access to a mapping system that can be utilized by both the locator and the facility owner/operator.” (Mapping #13).

- Participate in damage prevention councils – Operators should consider actively participating in local damage prevention councils and organizations. In many cases, gas distribution operators not only participate, they also sponsor, manage and lead efforts to bring the stakeholder parties together. This is a platform from which operators can reach out to other utilities and large project excavators in their area. This forum serves as a mechanism to resolve difference and to coordinate upcoming projects.

This practice is related to existing CGA Best Practices, particularly: "Project owners and facility owners/operators regularly communicate and coordinate with each other concerning future and current projects."(Planning & Design #4).

- Participate in pre-project meetings – Operators should consider participating in pre-project/pre-bid meetings held by governmental entities or other project owners. The benefit is that the operator makes all potential contractors aware of the presence of gas facilities within the scope of the proposed project. It is important to note that this can also be completed by having the designer denote the location of the natural gas facilities on the project plans.

This practice is related to existing CGA Best Practices, particularly: "A mandatory pre-bid conference is held and bids are only accepted from attending contractors." The practice description goes on to say, "Depending on the level of impact of proposed construction upon facilities in the excavation area, the project owner or project designer requires potential contractors to attend a mandatory pre-bid conference including underground facility owners/operators. This pre-bid conference is exercised to discuss, among other things, the particular facilities in the area and the requirements to properly protect, support, and safely maintain the facilities during excavation. Official minutes are taken and disseminated as written to all attendees." (Planning & Design #8).

- Mark new services – Where appropriate and feasible, operators should consider marking the location of newly "in service" mains and services at an ongoing construction site. Note that this is a temporary measure because of the increased vulnerability of newly installed facilities when excavation in the area continues even after gas construction is completed.
- Monitor excavations – Operators should consider the use of standby and monitoring for certain excavations.
- Evaluate program effectiveness – Operators should consider developing a program to evaluate the effectiveness of its damage prevention program.
- Identify repeat damagers – Operators should consider working with all parties to address frequent and willful violators of one-call statutes and safe digging practices, when all else fails.
- Prosecute damage claims – Operator should consider developing an effective damage claims program to ensure that at-fault damagers realize they are being held accountable for consequences of the damage. This is not just an economics issue – it can affect the behavior of excavators to dig safely and avoid future damages, thus improving pipeline safety. A key step in damage prevention is making the at-fault damagers consider the consequences for repeat damages.
- Relocate facilities – Operator should consider developing a process to consider the relocation of pipe, when necessary, to accommodate construction activity.

3. Incentives to reduce excavation damage

As previously noted, the EDPG concluded that an effective enforcement program is essential to reducing excavation related damages. The avoidance of violations and monetary penalties is one of the most effective incentives to reduce excavation related damages; however, there are a variety of other incentives that are also effective in reducing damages. A damage prevention stakeholder can either provide or receive these incentives. Incentives can be provided by operators, excavators, locators, and enforcement agencies. Specific incentives should be determined by individual stakeholder groups.

Following are examples of incentives/penalties for various stakeholder groups:

Incentives applicable to Excavators:

- Limit fines for noncompliance - Lower penalties can be used to recognize performance improvements as measured by damages/1000 tickets.
- Incentives for crews or individuals for reducing "at fault" damages:
  - Performance pay or bonuses – additional pay for no damages, a reduction in damages, etc.
  - Awards – formal awards in the form of plaques or certificates.
  - Recognition – Informal or formal public recognition (e.g. company news letter or trade magazine articles recognizing outstanding performance).
  - Penalties – The crew or individual responsible for the non-compliances could be subject to monetary penalties by the employer.
  - Suspension or termination - A crew or individual responsible for the non-compliance could be suspended or terminated depending on their culpability for the damage.
- Insurance premium discounts. Excavators with good safety records could be rewarded through lower insurance premiums.

Incentives applicable to One-Call notification centers:

- Monetary support for implementation of new technologies to improve performance. The incentive can often be provided by the One-Call centers governing board or in the form of state or federal grant monies. Examples of implementing new technologies include:
  - Improved mapping for both the operator and excavators use, and improved performance based on the CGA's One-Call Quality Standards Best Practices (One-Call Center #23).

Incentives applicable to underground facility operators/locators:

- Limit fines for noncompliance – Crew or individual incentives for reducing at fault damages in the form of:
  - Performance pay or bonuses. Additional pay for no damages, a reduction in damages, on time locate, etc.
  - Awards - formal awards like plaques or certificates.
  - Recognition – Formal recognition like articles in company news letters or trade magazines that recognizing outstanding performance.
  - Penalties – The individual locator or contract locating company responsible for the non-compliances could be subject to monetary penalties.
  - Suspension or termination – The crew or individual responsible for the noncompliance's are suspended or terminated depending on their culpability regarding a noncompliance.
- Support for implementing new technologies or processes to reduce damage including improved mapping and record accessibility, and use of improved or new locating technology.

Incentives applicable to the enforcement agency:

- Recognition by PHMSA for states with effective damage prevention programs.
- Enforcement agency's recognition of damage prevention stakeholders (operators, excavators, one-call centers, etc) for efforts to prevent excavation damages.
- Reduced penalties by the enforcing agency for:
  - Performance improvement – Demonstrated performance improvement result in reduced future penalties.
  - Education & training – Improvements or implementation damage prevention training for employees should be considered in mitigating penalties.
  - Participation and assistance with public outreach programs including display/distribution of damage prevention education materials, sponsorship of safe digging through various medium and attendance at damage prevention meetings, should also be considered to mitigate penalties.
  - Implementation of an effective auditing program (QC) – Such programs should be considered in mitigating penalties. These programs should address operators' in-house and contractor locators, and contractors installing pipeline facilities.
  - Implementation of effective new technologies or processes – such efforts should be considered in mitigating penalties.

4. Elements of an effective damage prevention law

The EDPG reviewed a number of states' existing damage prevention laws, rules and regulations and has concluded that an effective damage prevention law should contain provisions addressing the following requirements. This list should not be considered to be all-inclusive.

- One-call centers perform in accordance with established performance standards;
- One-call centers maintain a positive response system;
- Project designers obtain existing underground utility information and consider that information in their design processes;
- Operators having the right to bury and operate underground facilities are members of the one-call center for their area;
- Operators use all available information and means to accurately mark their underground facilities within the allowed time;
- Operators provide marking status to the one-call center;
- Accurate records of active facilities, and abandoned facilities if available, are maintained by operators and used for marking of facilities;
- Locators are trained in applicable locating standards and practices;
- For complex jobs, a process for meetings between excavators and operators is established;
- Excavators planning to excavate or demolish notify the one-call center and wait the required time before excavating;
- Excavators contact the one-call center and obtain the marking status before excavating;
- Excavators inspect the excavation sites to check for "clear evidence" of unmarked facilities before excavating;
- Excavators request marking if clear evidence of unmarked facilities is present;
- Excavators use reasonable care, including hand digging, in close proximity to underground facilities;
- State agencies involved with pipeline safety are authorized to actively enforce their state laws;
- One-call centers, operators, and state agencies involved in enforcement actively educate all stakeholders, including the public, on requirements of state damage prevention laws;

- Meaningful incentives are provided to reduce damage to underground facilities.

5. Public Education and Awareness

The continued growth in the nation's economy requires the expansion of the underground utility infrastructure to provide essential services to the citizens and businesses around the country. New technologies such as fiber are employed to provide improved telecommunications services to every home. Hurricanes Katrina and Rita damaged and or destroyed utility facilities in several states. These and similar factors have placed tremendous demands on all damage prevention stakeholders including the one-call center, operators and locators. To ensure public safety and reliability of service, all damage prevention stakeholders must cooperate in carrying out not only their respective responsibilities, but must help with overarching national damage prevention education programs.

The EDPG recognizes that effective damage prevention requires that stakeholders be aware of the presence of underground facilities, the dangers associated with damage to those facilities, and their responsibilities related to preventing excavation damage to the facilities. The EDPG also recognizes that reductions in the numbers of excavation damages to pipelines in recent years are attributed to factors such as increased emphasis on damage prevention education and awareness efforts. Damage prevention educational efforts must continue to be promoted and supported, including those efforts of the CGA which garner the representative participation of virtually all stakeholder elements.

Public Awareness Regulation

In 2005 the PHMSA issued new regulations aimed at enhancing public awareness about pipelines. The new regulations require pipeline operators to develop and implement enhanced public awareness programs. The amendments for developing and implementing public awareness programs address the requirements of the Pipeline Safety Improvement Act of 2002 and incorporate by reference the guidelines provided in the American Petroleum Institute (API) Recommended Practice (RP) 1162, ''Public Awareness Programs for Pipeline Operators.'' The regulations require that in developing its program, an operator must 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.

These new regulations concern pipeline operator efforts to improve public awareness of pipeline operations and safety issues through enhanced communications with:

- The public including residents and places of congregation, such as businesses, schools, hospitals, prisons, and other places where people gather in the pipeline vicinity and its associated rights-of-way;

- State and local emergency response and planning officials (*e.g.*, State and county emergency management agencies and local emergency planning committees) and first responder organizations;

- Local public officials and governing councils of affected municipalities and school districts; and

- Excavators.

Effective public awareness programs are vital to continued improvements in damage prevention and safe pipeline operations. Operators' public education programs to ensure they are being implemented effectively and in accordance with the regulatory requirements should be monitored.

Three-digit Dialing for Facility Locate Requests

In 2005, the Federal Communications Commission (FCC) approved the requirement for implementation by April 13, 2007, of a nationwide three-digit dialing number ("811") for excavators to use in contacting their respective state one-call centers. This requirement is a landmark that will reshape the "Call Before You Dig" industry and the damage prevention landscape. Implementation of "811" dialing for locate requests nationwide will make it much easier for excavators to remember the number to dial the one-call center and increase the likelihood that they make the required call to request facility locates before digging. This will help to reduce the number of excavation damages, resulting from failure of the excavator to call the one-call center before digging. Recent industry statistics report that more than 40 percent of damages were preceded by the failure of the excavator to call the one-call center to request marking of facilities in the area of the excavation. Consequently, efforts to promote the use of "811" should be included at the core of any damage prevention education and awareness efforts.

Common Ground Alliance

The Common Ground Alliance was formed at Congressional direction and with the PHMSA's support following completion of the landmark <u>Common Ground Study of One-Call Systems and Damage Prevention Best Practices</u> in 1999. The CGA has become recognized as the leading organization in nationwide underground damage prevention efforts. A CGA focus is that damage prevention can be achieved through shared responsibility among all stakeholders. The CGA has over 1,200 individual members, 135 member organizations, and 25 sponsors.

The CGA continues to look at ways to prevent damage to underground facilities. Its member-driven committees develop and implement targeted education and awareness programs; identify, publish and promote the implementation of Damage Prevention Best Practices; collect, analyze and report damage data; and foster and support research and development. The CGA Regional Partners Program extends these efforts out to the grass-roots level, working collectively and cooperatively with local damage prevention organizations in communities throughout North America.

Some of the CGA's current public education and awareness efforts include:

- Promotion of "811" three-digit dialing – The CGA was prominent in promoting the establishment of "811" and plans to work with One Call Systems International (OCSI) to develop a national educational campaign to promote use of the number and to develop data to monitor its use.

- **"Dig Safely"** – The CGA provides the stewardship for **Dig Safely**. This damage prevention message is highly regarded and widely used by various stakeholders in their own damage prevention efforts. The CGA develops and provides educational media for promoting **Dig Safely**. Four steps to safe digging and damage prevention are promoted:
  - Call before you dig
  - Wait the required amount of time
  - Respect the marks
  - Dig with care

  Another step, **<u>Locate Accurately</u>**, was added to the **Dig Safely** mantra by the CGA in 2005. It emphasizes the locators' responsibility to accurately locate facilities.

  <u>Agricultural Dig Safely Campaign</u> – A survey conducted in 2003 by the CGA Educational Programs Committee indicated the need for educational messages geared toward the agricultural community. As a result, the CGA developed an educational campaign promoting the Dig Safely message to this target audience.

- Best Practices – The CGA Damage Prevention Best Practices are published in handbooks and CD versions. The latest version of the Best Practices are available for free to all stakeholders.

- Compliance & Enforcement of One-call Laws – The CGA continues to emphasize the Compliance and Enforcement Best Practices agreed to by the 15 stakeholder groups in the original Common Ground Study. All participating stakeholder groups continue to recognize the need to enforce compliance as a major driver in damage prevention.

In summary, the EDPG concludes that effective damage prevention education and public outreach programs be designed and implemented. These programs should be based on damage data by cause, responsible parties and other appropriate factors. These programs should be evaluated on a regular basis to determine their effectiveness.

6. Legislative actions for reducing excavation related damages to enhance distribution integrity

As has been stated a number of times in this report, the EDPG recognizes that one of the most effective ways to reduce damages to the distribution pipeline infrastructure is to have an effective damage prevention program.

On April 1, 1983[52], the PHMSA began requiring operators of pipelines, subject to the requirements of 49 CFR, Part 192, to have damage prevention programs in place in an effort to curb damages to pipelines from excavation related activities. Discussions from the preamble to this amendment recognized the fact that damages to pipelines still occur at an "alarming rate" even though the pipeline operator had responded in a timely manner and marked the underground pipeline facilities. This regulatory approach has limited effectiveness in that only pipeline operators may be penalized by the PHMSA or an agency with a certification under 49 USC §60105. The EDPG finds that damage reduction is significantly greater when enforcement is applied equally, fairly and consistently to all violators of the provisions of the damage prevention laws, rules and regulations.

As discussed in the data review and analysis portion of this report, damages to distribution pipelines are significantly lower in states that have effective damage prevention programs in place. Effective programs have been identified as those which contain, among other things, an active, fair, and balanced approach for enforcement of damages to underground facilities, particularly pipelines, as a part of the overall program. One-call legislation is effected at the State level. While almost all state legislation provides for civil penalties or injunctive relief for parties that violate requirements of the laws, many rely on the enforcement of these laws to be carried out by entities (e.g. attorneys' general, local district attorneys, etc.) that have little interest or lack the resources to pursue enforcement. As recognized and adopted as a CGA Best Practice, the most effective enforcement is accomplished by placing this authority within the control of an entity that has a structured review process. Two types are described in detail in the CGA Enforcement Best Practices. Those two types are used in the states identified in this report as having known comprehensive damage prevention programs. The authority for the enforcement within these states resides within the agencies having certification under USC §60105. The EDPG has concluded that enforcement authority for damage prevention and one-call requirements should reside within the agencies having responsibility for pipeline safety, since pipeline safety and damage prevention are intrinsically linked. This also prevents exposing operators to enforcement of Part 192 by different agencies.

Many states have made numerous unsuccessful attempts throughout the years to modify and enhance their damage prevention legislation to include the enforcement, education, and incentives briefly described herein. In some cases, monetary resources may be the obstacle that must be overcome in order to modify the authority roles and implement effective damage prevention programs. Therefore, the EDPG has included a provision in

[52] FR Doc. 82-8524; March 25, 1982

the draft legislative language in Exhibit 1 to address federal funding to assist states to carry out effective damage prevention programs. The EDPG strongly believes these funds should be provided for by Congress through some means other than pipeline user fees as all owners and operators of underground facilities will benefit from comprehensive damage prevention programs.

The EDPG encourages PHMSA, the pipeline industry and other stakeholders urge Congress to adopt the proposed legislation presented in Exhibit 1 in the next pipeline safety reauthorization[53].

7. Performance metrics and program evaluation

The EDPG has determined that damage prevention program metrics are critical to evaluate the effectiveness of damage prevention efforts, and to determine trending, progress and areas for additional emphasis. Damage prevention program metrics should be managed by the state's agency with responsibility for distribution pipeline safety, and by individual operators.

There are two different types of program metrics; damage prevention program metrics that should be submitted to PHMSA (in addition to current data on the annual report) as part of distribution system safety reporting under the Distribution Integrity Management program; and metrics for internal use by the operator for individual damage prevention program evaluation.

The EDPG has identified two damage prevention performance metrics that should be provided to PHMSA:

- Number of excavation caused damages (as defined below), and
- Normalized damages (damage ratio) defined as damages per 1000 tickets

"Damages" are defined as any impact or exposure which, according to the operator's practices, results in a repair or replacement of an underground facility, related appurtenances or supporting material.

A "Ticket" is defined as the receipt of information by the underground facility operator from the notification center regarding onsite meetings, project design or a planned excavation.

The damage metric provides a useful indicator of the total number of excavation events having impacted an operator's pipeline facilities that could have the potential for an incident. However, an evaluation of damages alone may result in misleading conclusions. For example, if damages are declining, it may be due to successes in the state or operator damage prevention program, or it may be the result of an economic downturn and the associated decline in construction activity. Conversely, an increase in damages may be

[53] Conforming changes to 49 CFR Part 198 also will be needed if this legislation is enacted.

due to an improvement in the economy and the associated increase in construction activity, and may not be the result of an ineffective damage prevention program.

The normalized damages (damage ratio) metric provides a weighted average of damages per 1000 tickets. This metric provides a more useful indication of the successes of damage prevention programs by accounting for changes in the construction activity resulting from upturns or downturns in the economic environment, or major capital projects in a state, such as a telecommunications project to install fiber-optics in major metropolitan areas throughout the state.

In addition to the two performance metrics that should be reported to PHMSA as measures of an operator's damage prevention program performance, the EDPG also identified performance metrics that should be used internally by natural gas distribution system operators to evaluate their damage prevention programs. Specifically, these performance metrics should be used to closely monitor the program performance, analyze trends and take actions on areas needing improvement or additional emphasis.

Internal metrics may include the following:

- Ratio of ticket no-show* to total tickets received by the operator
- Failure by notification center to accurately transmit tickets to the operator
- Damages by cause, facility type (mains, services), and responsible party. Cause categories to include:
    - Excavator's failure to call
    - Excavator's failure to provide accurate ticket (e.g., wrong address)
    - Operator's failure to mark
    - Operator's failure to mark accurately
    - Excavator's failure to wait required time for marking
    - Excavator's failure to protect marks
    - Excavator's failure to hand dig within tolerance zone
    - Excavator's failure to hand dig
    - Excavator's failure to properly support and protect facility
    - Others

* "no-show" means those tickets that were not responded to by the locators within the allowed time.

These internal metrics should be available for inspection by the state's pipeline safety program regulator upon request.

Cost/Benefit Analysis

The EDPG is providing the following for consideration of any cost/benefit analysis:

- Fatalities and injury data from 2000 - 2004 related to excavation damage should be considered. Number of fatalities and injuries should be valued based on DOT's standard protocols.
- Available PHMSA property damage information attributable to mechanical damages should be used for calculation of annual projections.
- Costs for repairs to pipelines are estimated at \$500 – \$750 for damages to service lines and \$1000 – \$2000 for damages to mains. These numbers were provided by industry and state team member resources. More precise numbers are desirable.
- Excavator down time for routine damages, i.e., service lines and minor damages to mains, is estimated at 2 – 4 hours each at \$200 per occurrence. Better estimates are desirable.
- Business interruption costs on the part of the consumer may occur during certain damages, however these are not common and would be difficult to ascertain.
- Other costs that should be considered:
  - Unrecoverable damage claims
  - Damage investigation time
  - Administrative costs to process claims
  - Claims defense/litigation costs
  - Costs associated with additional data collection activities for internal and external reporting purposes
- One-call center costs associated with increased locate ticket volumes. One of the results of introducing effective enforcement as part of a comprehensive damage prevention program into a state which previously did not have it is that locate ticket volumes will increase faster than they otherwise would have. During the period 2000 to 2004, ticket volumes in states without comprehensive programs increased on average 6.57 percent per year. A comparison to ticket volumes from Virginia for an equivalent period of time immediately following the implementation of enforcement indicated an average annual ticket volume increase of 10.69 percent or an average of 4.12 percent more than in states without comprehensive plans.

  In 2004 the total locate ticket volume for all states without comprehensive damage prevention programs was a total of 19,326,111 tickets. Taking that 4.12 percent annual ticket volume premium and applying it across the nation, one can project that tickets volumes would increase annually by an additional 796,235 tickets per year, if all states adopted effective enforcement. At an average cost of $16.50 per ticket ($1.50 per ticket received and $15.00 per locate performed) that would project out to an added annual cost of $13,137,877.

<u>State Government costs</u>

These costs include:

- Initial administrative costs incurred to develop and pass legislative changes at state level; and
- Costs associated with enforcement, program partnership, and ongoing administration.

<u>Additional costs/ benefits for other utilities/political subdivisions</u>

- Costs/benefits for entities not currently regulated by pipeline safety which may result from a comprehensive damage prevention program should be considered. Benefits include reduced damages to other utility infrastructure, personal injuries and property damage. Currently, such data may not be readily available.

<u>Societal benefits</u>

Using standard DOT figures for life and injuries correlated to the data provided in the data section of this report (i.e. 40 percent less damages than a state without effective damage prevention program), expected reduction in loss of life, number of injuries, and reduced number of property damages can be calculated.

Excess Flow Valves

It is important to note that the installation of an EFV on a distribution service line will not reduce the number of excavation damages to the distribution infrastructure, or ensure pipeline integrity. However, the EFV has the potential to minimize the consequences of excavation damage after the damage has occurred. Therefore, the EDPG has concluded that EFVs are one tool that should be considered by operators in addressing the potential consequences of excavation damage on new or renewed single family residential service lines.

Exhibit 1
Draft Federal Legislation

§ 60105. State pipeline safety program certifications

Subsection (b) of section 60105 is amended by revising paragraph (b)(4) to read as follows:

> "(4) has or will adopt, within 36 months of [the date of enactment of this amendment], a program designed to prevent damage by excavation, demolition, tunneling, or construction activity to the pipeline facilities to which the certification applies that meets the requirements of section 601XX."
>
> > (i) If a state fails to develop and implement an excavation damage prevention program in accordance with item (4), above, the Secretary shall take any action deemed appropriate to ensure an effective damage prevention program within that state.
> >
> > (ii) Annually, if a state can demonstrate to the Secretary that it has taken all reasonable actions to implement such a program without success, funding for the remainder of its pipeline safety program shall not be affected.

§ 601XX. State damage prevention programs

(a) Minimum standards. In order to qualify for a grant under this section, each State authority (including a municipality if the agreement applies to intrastate gas pipeline transportation) having an annual certification in accordance with section 60105 or an agreement in accordance with section 60106 shall have an effective damage prevention program that, at a minimum, includes the following elements:

> (1) Effective communication between operators and excavators- Each state program shall provide for appropriate participation by operators, excavators, and other stakeholders in the development and implementation of methods for establishing and maintaining effective communications between stakeholders from receipt of an excavation notification until successful completion of the excavation, as appropriate.
>
> (2) Fostering support and partnership of stakeholders- Each state program shall include a process for fostering and ensuring the support and partnership of stakeholders including excavators, operators, locators, designers, and local government in all phases of the program.
>
> (3) Operator's use of performance measures – Each state program shall include a process for reviewing the adequacy of a pipeline operator's internal performance measures regarding persons performing locating services and quality assurance programs.

(4) Partnership in employee training – Each state program shall provide for appropriate participation by operators, excavators, and other stakeholders in the development and implementation of effective employee training programs to ensure that operators, the one-call center, the enforcing agency and the excavators have partnered to design and implement training for operators,' excavators' and locators' employees.

(5) Partnership in public education – Each state program shall include a process for fostering and ensuring active participation by all stakeholders in public education for damage prevention activities.

(6) Dispute resolution process – Each state program shall include a process for resolving disputes that defines the state authority's role as a partner and facilitator to resolve issues.

(7) Fair and consistent enforcement of the law- Each state program shall provide for the enforcement of its damage prevention laws and regulations for all aspects of the excavation process including public education. The enforcement program must include the use of civil penalties for violations assessable by the appropriate state authority.

(8) Use of technology to improve all parts of the process – Each state program shall include a process for fostering and promoting the use, by all appropriate stakeholders, of improving technologies that may enhance communications, locate capability, and performance tracking.

(9) Analysis of data to continually evaluate/improve program effectiveness – Each state program shall include a process for review and analysis of the effectiveness of each program element and include a process for implementing improvements identified by such program reviews.

(b) Application. If a State authority files an application for a grant under this section not later than September 30 of a calendar year, the Secretary of Transportation shall review that State's damage prevention program to determine its effectiveness. For programs determined to be effective, the Secretary shall pay not more than [$nn] of the cost of the personnel, equipment, and activities the authority reasonably requires during the next calendar year to carry out an effective damage prevention enforcement program as defined in (a) of this section. If appropriate, the Secretary may make payments under this section without regard to the 50 percent limitation referenced in section 60107(a).

(c) Authorization of Appropriations. There is authorized to be appropriated to the Secretary for carrying out this section [$nn] for each of the fiscal years 2006 through 2010. Such funds shall remain available until expended. Any funds appropriated to carry out this section shall be derived from general revenues and shall not be derived from user fees collected under section 60301.

Attachment D

Integrity Management for Gas Distribution Pipelines

Data Group Report

October 14, 2005

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Acronyms

AGA – American Gas Association
AGF – American Gas Foundation
APGA – American Public Gas Association
DIRT – Damage Information Reporting Tool
DIMP – Distribution Integrity Management Program
DOT – Department of Transportation
EIA – Energy Information Adminstration
EDPG – Excavation Damage Prevention Group
EFV – Excess Flow Valve
IM – Integrity Management
LP – Liquid Propane
M-K – Mann-Kendal statistical test for data trends
NAPSR – National Association of Pipeline Safety Representatives
NARUC – National Association of Regulatory Utility Commissioners
PHMSA – Pipeline and Hazardous Materials Safety Administration

Executive Summary

Data Group Mission from the Report to Congress

To evaluate existing data and to collect more data as needed to identify the nature, significance, and trends in threats affecting distribution pipeline systems and the effectiveness of current programs addressing these threats.

Data Sources and Limitations

Data Sources	**Data Limitations**
Incident Reports • Submitted for Reportable Incidents • Typically ~ 125 per year of which ~ 45 Involve Injury or Fatality[54]	*Incident Reports* • Limited Set of Cause Categories • New Causes Added in 2004 • Inconsistent (over) Reporting on Incidents Involving Property Damage • Insufficient Detail to Determine whether EFV would have Mitigated Incident
Annual Reports • Reports Leaks Removed by Cause • Reports Miles of Main and Number of Services by Material of Construction • Typically ~ 170,000 leaks per year on Mains and ~ 350,000 per year on Services[55]	*Annual Reports* • Limited Set of Cause Categories • New Categories Added in 2004, cause categories different from incidents • No Data on Leaks Removed by Material • Inconsistent Classification of Leak Severity • No Data on Master Meter or LPG Operators

Findings and Conclusions Related to Questions Addressed by the Data Group

9. *Which threats have greatest impact on distribution system safety?*

   Threats having the greatest impact on distribution system safety are characterized below, with the source of the conclusion in parenthesis:
   - The dominant cause of distribution pipeline incidents (reportable) is "excavation damage", while the second and third leading causes are "other outside force" and "natural force", respectively (Allegro[56])
   - The dominant cause of distribution pipeline leaks removed is corrosion for both mains and services (Data Group)
     - "Excavation damage" is nearly as significant as "corrosion damage" for services (Data Group)
     - The second and third leading causes for both mains and services are "excavation damage" and "material/welds", respectively (Data Group)

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[54] The numbers of incidents per year are based on the incidents occurring over the thirteen year period covered by the AGF study - American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure", January, 2005.

[55] Based on the 2004 Annual Report data on leaks removed

[56] Trench, Cheryl J., "Safety Incidents on Natural Gas Distribution Systems: Understanding the Hazards", April 2005.

- The percentage of incidents caused by corrosion is approximately 4%, indicating that corrosion is currently managed to prevent it from becoming one of the major contributors to reportable incidents (Data Group)

10. *Do data show whether threats are of increasing or decreasing concern, thereby supporting any conclusions on the effectiveness of existing integrity management programs?*

    The following trends have been identified, with the source of the conclusion in parenthesis:

- A decreasing trend in the rate of reportable distribution incidents resulting in fatalities and injuries exists for the preceding 13-year study period (AGF[57])
- No statistically significant trend was determined for total reportable distribution incidents for the 13 year study period (AGF)
- There is a downward trend for reportable incidents resulting in fatalities or injuries caused by outside force damage (AGF)
- There appears to be a slight downward trend in corrosion-caused leaks removed, and there appears to be a decreasing trend in leaks removed caused by third party damage - statistical analysis was not performed (Data Group)
- While anecdotal evidence indicates there should be a downward trend in the mileage of certain materials that are more likely to leak, data from the Annual Reports in this area are too inaccurate to support this finding (Data Group)

11. *How might the current performance baseline be characterized?*

- The national performance baseline for the distribution pipeline system may be characterized using the following three factors:
    - DOT reportable incident statistics
    - Data on leaks removed
    - Information on system physical characteristics (e.g., miles of materials with an increased leakage potential such as unprotected ferrous materials or cast iron)
- So few incidents occur that incidents are not a meaningful baseline performance measure for operators or for individual states - most operators and many states experience zero incidents in a typical year
- Because of year-to-year fluctuations in the available data, the baseline related to incidents and leaks removed should be established based on an average of data over a three or five year period
- The current baseline related to the maturity of distribution integrity management (IM) practices cannot be determined based on current reporting requirements,
- Final determination of the best national baseline performance parameters should await identification of any changes to reporting requirements.

---

[57] American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure," January, 2005.

12. *Do data exist to support either focusing of new requirements on certain industry segments (e.g., master meters, propane operators or small operators) or excluding segments from new requirements?*

    Based on analysis of the leakage data, we can conclude that there is *no clear basis* for excluding operators of any size from additional requirements designed to improve the integrity of distribution pipeline systems. Since no data exist for master meter and propane operators, no analysis was possible.

13. *Do data show any significant differences among states that may impact the findings from this Program?*

    As a result of the very small number of incidents (often zero) in an individual state, differences among states in incident rates are not statistically significant. Therefore, conclusions are not possible from these data. Differences in "leaks removed" normalized to miles of main or number of services correlate well with the fraction of unprotected steel pipe in a state. This correlation, combined with large differences in miles of unprotected steel pipe, masks any differences that may exist due to the relative effectiveness of state programs. Hence, neither data on incidents nor on leaks removed shed light on the effectiveness of individual state programs.

    The Excavation Damage Prevention Group has collected data on damages to distribution pipelines and on tickets issued per state. Conclusions based on analysis of these data are presented in their report.

14. *What changes to data reporting requirements might be valuable?*

    Potentially useful changes to data collection requirements being considered include:

    - Careful review of Damage Information Reporting Tool (DIRT) and state reporting forms should be undertaken to determine whether additional information should be added when incident or leak cause is excavation damage.
    - Annual Reports should be revised to require the reporting of only "leaks eliminated that required immediate action" (also termed "hazardous leaks"); the material of the pipe from which these leaks were eliminated should also be reported. The American Gas Association (AGA) representative did not support the conclusion regarding the value of reporting the material of pipe from which leaks are removed.
    - There would be considerable value derived from formation of a joint stakeholder group to conduct an annual review of safety performance metrics data, to resolve issues, and to produce a national performance metrics report.
    - Improvements in incident data collection requirements could contribute to better decisions on whether to install excess flow valves (EFVs).
    - Include a check box on the incident report form indicating whether incident is being reported at discretion of operator (with appropriate criteria).

15. *What do we currently know about the performance and cost effectiveness of EFVs?*

- Over 6.3 million EFVs have been installed in the USA,
- Analysis of information from surveys completed to date indicates that, if correctly specified and installed, EFVs function as designed,
- EFVs will not function in all applications - up to 60% of new services in Connecticut, a state that supports use of EFVs, will not support EFV use
- Different operators have reached different conclusions on whether the overall cost of installing EFVs on new and replacement services is favorable or unfavorable relative to that of complying with current notification requirements; operator conclusions seem to reflect their assumptions (e.g., whether or not they include litigation risk, how they treat cost recovery, the probability of an incident actually occurring)

16. *Would gathering of additional data on EFVs contribute to clarifying their benefits or costs?*

There is limited value associated with carrying out an expansive forward-looking EFV data collection effort. The Data Group concludes that the following represents a more effective course of action:

- AGA moving forward with its planned effort to promote exchange of factual performance and reliability information among its membership,
- American Public Gas Association (APGA) continuing to communicate real world experience with EFVs among its members,
- Pipeline and Hazardous Materials Safety Administration (PHMSA), APGA and AGA developing EFV feasibility criteria, considering factors such as the following: line pressure, expected future changes in line pressure, the presence of liquids in the line, the presence of solid particles in the line, environmental conditions that could reduce EFV functionality, and the length of line from main to meter.

Documentation Supporting Findings and Conclusions

The following documents support Data Group Findings and Conclusions.

1. Incident and Leak Data Analysis - Exhibit A
2. Performance Baseline and Changes to Reported Data - Exhibit B
3. Potential Role and Value of a Forward-Looking EFV Study - Exhibit C
4. Summary of Existing Information on EFV Use and Performance - Exhibit D
5. Additional Information on EFV Performance - Exhibit E

Introduction

The Data Group was constituted as part of the Distribution Integrity Management Program (DIMP) with the following mission:

> To evaluate existing data and to collect more data as needed to identify the nature, significance, and trends in threats affecting distribution pipeline systems and the effectiveness of current programs addressing these threats.

Beginning on March 16, 2005, the Data Group assembled and began work under the chairmanship of Michael Thompson, Director of Pipeline Safety for the Oregon Public Utility Commission. Membership in the Group at the time this report was completed is shown in the table below.

Name	Organization
Erickson, John	American Public Gas Assoc.
Evans, Rex	Illinois Commerce Commission
Johnson, Pam	Pacific Gas & Electric
Kent, Kevin	City of Mesa
Lemoff, Ted	National Fire Protection Association - Public
Little, Roger	Pipeline and Hazardous Materials Safety Administration – DOT
Murdock, Phillip	ATMOS Energy
Pott, Steve	Colorado Public Utilities Commission
Talukdar, Piyali	Volpe Center
Thompson, Michael (Chair)	Oregon Public Utility Commission
Wood, Paul (Support)	Cycla Corp.

Expectations and Associated Actions

A summary of expectations for the Data Group is presented in this section. This list has been abstracted from the PHMSA Report to Congress that transmitted its plan for pursuing improvements to the integrity management of distribution systems. Expectations presented in that Report have been consolidated as appropriate. Following each expectation is a summary of the approach the Data Group took to address the expectation, the results or conclusions reached, and a reference to the Exhibit in which the work is reported.

Analyze Current Data

> *Summarize information from existing leakage and incident data relating to the nature, significance, and trends in threats affecting distribution pipeline systems and the effectiveness of current programs addressing these threats*

Approach Taken

Two types of data are reported that relate to distribution pipeline safety: DOT reportable incident statistics[58] and data on leaks removed as reported in Annual Reports[59] submitted by most jurisdictional operators. The Data Group used two existing analyses of incident experience: a study by the AGF that analyzed distribution system incidents that occurred during the period 1990-2002 completed in 2004[60], and a more recent evaluation of incidents that occurred during the period 1999-2003 carried out by Allegro Energy Consulting under contract to PHMSA[61]. In addition, the Data Group carried out confirmatory analysis using incident data from 2004, the first report year after the incident cause categories were expanded, and carried out its own analysis of 2004 data to identify insights regarding the relative significance of threats, and to evaluate any observable differences among operators and states.

Result or Conclusion

The Data Group first looked into how the current performance baseline might be characterized, with the following conclusions:

- The national performance baseline for the distribution pipeline system may be characterized using the following three factors:
  - DOT reportable incident statistics
  - Data on leaks removed
  - Information on system physical characteristics (e.g., miles of materials with an increased leakage potential such as unprotected ferrous materials or cast iron)
- So few incidents occur that incidents are not a meaningful baseline performance measure for operators or for individual states - most operators and many states experience zero incidents in a typical year
- Because of year-to-year fluctuations in the available data, the baseline related to incidents and leaks removed should be established based on an average of data over a three or five year period
- The current baseline related to the maturity of distribution IM practices cannot be determined based on current reporting requirements,
- Final determination of the best national baseline performance parameters should await identification of any changes to reporting requirements.

Threats having the greatest impact on distribution system safety are characterized below, with the source of the conclusion in parenthesis:

[58] Incident defined at 49 CFR 191.3. Reporting requirements at 49 CFR 191.5 and 191.9.
[59] Annual Report for Gas Distribution Systems (PHMSA F 7100.1-1)
[60] American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure," January 2005
[61] Allegro Energy Consulting, "Safety Incidents on Natural Gas Distribution Systems: Understanding the Hazards," April 2005

- The dominant cause of distribution pipeline incidents (reportable) is "excavation damage", while the second and third leading causes are "other outside force" and "natural force", respectively (Allegro)
- The dominant cause of distribution pipeline leaks removed is corrosion for both mains and services (Data Group)
    - "Excavation damage" is nearly as significant as "corrosion damage" for services (Data Group)
    - The second and third leading causes for both mains and services are "excavation damage" and "material/welds", respectively (Data Group)
- The percentage of incidents caused by corrosion is approximately 4%, indicating that corrosion is currently managed to prevent it from becoming one of the major contributors to reportable incidents (Data Group)

The following trends have been identified, with the source of the conclusion in parenthesis:

- A decreasing trend in the rate of reportable distribution incidents resulting in fatalities and injuries exists for the preceding 13-year study period (AGF)
- No statistically significant trend was determined for total reportable distribution incidents for the 13 year study period (AGF)
- There is a downward trend for reportable incidents resulting in fatalities or injuries caused by outside force damage (AGF)
- There appears to be a slight downward trend in corrosion-caused leaks removed, and there appears to be a decreasing trend in leaks removed caused by third party damage – statistical analysis was not performed (Data Group)
- While anecdotal evidence indicates there should be a downward trend in the mileage of certain materials that are more likely to leak, data from the Annual Reports in this area are too inaccurate to support this finding (Data Group)

<u>Applicable Exhibits</u>

Incident and Leak Data Analysis - Exhibit A
Performance Baseline and Changes to Reported Data - Exhibit B

Evaluate Effectiveness of Current Programs

> *Assemble information and evaluate the effectiveness of current programs addressing identified threats for each State to determine if any significant differences or similarities exist that may impact the findings of this program*

<u>Approach Taken</u>

The Data Group carried out an analysis of 2004 leakage data from the Annual Reports.

Result or Conclusion

As a result of the very small number of incidents (often zero) in an individual state, differences among states in incident rates are not statistically significant. Therefore, conclusions are not possible from these data. Differences in "leaks removed" normalized to miles of main or number of services correlate well with the fraction of unprotected steel pipe in a state. This correlation, combined with large differences in miles of unprotected steel pipe, masks any differences that may exist due to the relative effectiveness of state programs. Hence, neither data on incidents nor on leaks removed shed light on the effectiveness of individual state programs.

The Excavation Damage Prevention Group has collected data on damages to distribution pipelines and on tickets issued per state. Conclusions based on analysis of these data are presented in their report.

Applicable Exhibit

Incident and Leak Data Analysis - Exhibit A

Identify Candidate Changes in Reporting Requirements

> *Identify candidate changes in reporting requirements to support improving distribution safety performance and to facilitate future evaluation of the effectiveness of actions implemented as a result of changes to distribution integrity management requirements*

Approach Taken

The Data Group carried out a structured discussion of the strengths and limitations of existing data sources in the light of its data analysis experience.

Result or Conclusion

Potentially useful changes to data collection requirements being considered include:

- Careful review of DIRT and state reporting forms should be undertaken to determine whether additional information should be added when incident or leak cause is excavation damage
- Annual Reports should be revised to require pipe material as well as leak cause
- Hazardous leaks (those requiring immediate attention) should be reported as a subset of all leaks eliminated
- The Data Group was not able to reach consensus on the need for any additional national-level leak-related reporting requirements. Members were divided on whether data on non-hazardous leaks were in any way significant to safety at the national level or are properly a reflection of the effectiveness of individual operator leak management practices.

(In its deliberation to make the results from the various group findings and conclusions more internally consistent, the Coordinating Group combined and revised the above three findings as follows:

> Annual Reports should be revised to require the reporting of only "leaks eliminated that required immediate action" (also termed "hazardous leaks"); the material of the pipe from which these leaks were eliminated should also be reported.

All members of the coordinating Group supported this approach except the AGA representative who did not support the conclusion regarding the value of reporting the material of pipe from which leaks are removed. In addition, the Coordinating Group found that there would be considerable value derived from formation of a joint stakeholder group to conduct an annual review of safety performance metrics data, to resolve issues, and to produce a national performance metrics report. This revised wording is reflected in the Executive Summary of this report.)

- Improvements in incident data collection requirements could contribute to better decisions on whether to install EFVs.
- Include a check box on the incident report form indicating whether incident is being reported at discretion of operator (with appropriate criteria).

<u>Applicable Exhibit</u>

Performance Baseline and Changes to Reported Data - Exhibit B

Determine if Data can Characterize the Risk Spectrum

> *Determine whether data can be used to characterize the risk from the spectrum of distribution operators. These data could potentially influence the nature of requirements for the smallest operators*

<u>Approach Taken</u>

The Data Group carried out an analysis of 2004 leakage data.

<u>Result or Conclusion</u>

Based on analysis of the leakage data, we can conclude that there is *no clear basis* for excluding operators of any size from additional requirements designed to improve the integrity of distribution pipeline systems. Since no data exist for master meter and propane operators, no analysis was possible.

<u>Applicable Exhibit</u>

Incident and Leak Data Analysis - Exhibit A

Analyze EFV Experience

> *Analyze available experience with EFVs including (a) conditions under which their application is considered feasible and potential beneficial, (b) experience with their performance and effectiveness, and (c) costs and benefits of installation and operation*

Approach Taken

The Data Group assembled numerous available studies conducted during the past year to help clarify what is actually known about EFV installation and performance experience[62]. These studies, commissioned by PHMSA, NARUC and NAPSR were summarized and documented by the Data Group. In addition, the Data Group conducted its own survey of a group of ten operators with significant experience installing EFVs and operating systems having many EFVs[63].

Result or Conclusion

What do we currently know about the performance and cost effectiveness of Excess Flow Valves (EFVs)?

- Over 6.3 million EFVs have been installed in the USA,
- Analysis of information from surveys completed to date indicates that, if correctly specified and installed, EFVs function as designed,
- EFVs will not function in all applications - up to 60% of new services in Connecticut, a state that supports use of EFVs, will not support EFV use
- Different operators have reached different conclusions on whether the overall cost of installing EFVs on new and replacement services is favorable or unfavorable relative to that of complying with current notification requirements; operator conclusions seem to reflect their assumptions (e.g., whether or not they include litigation risk, how they treat cost recovery, the probability of an incident actually occurring)

Would gathering of additional data on EFVs contribute to clarifying their benefits or costs?

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[62] "Survey Responses of State Public Utility Commissions on Excess Flow Valve", Ken Costello - Senior Institute Economist, The National Regulatory Research Institute at The Ohio State University, June 1, 2005.
"PHMSA/NAPSR Survey of State Experience with EFV Performance - Summary of Responses", Anne Marie Joseph, PHMSA, May 25, 2005.
"Excess Flow Valve Survey Summary", C. B. Oland, Oak Ridge National Laboratory, September 1, 2005.
"Evaluation of Excess Flow Valves in Gas Distribution Systems", Mona C. Mc Mahon, General Physics Corporation, August, 2005.
[63] "Summary of Survey on Excess Flow Valve Experience", Rex Evans, Illinois Commerce Commission, DIM Program Data Group, September, 2005.

There is limited value associated with carrying out an expansive forward-looking EFV data collection effort. The Data Group concludes that the following represents a more effective course of action:

- AGA moving forward with its planned effort to promote exchange of factual performance and reliability information among its membership,
- APGA continuing to communicate real world experience with EFVs among its members,
- PHMSA, APGA and AGA developing EFV feasibility criteria, considering factors such as the following: line pressure, expected future changes in line pressure, the presence of liquids in the line, the presence of solid particles in the line, environmental conditions that could reduce EFV functionality, and the length of line from main to meter.

Applicable Exhibits

- Potential Role and Value of a Forward-Looking EFV Study - Exhibit C
- Summary of Existing Information on EFV Use and Performance - Exhibit D
- Additional Information on EFV Performance - Exhibit E

Exhibit A
Incident and Leak Data Analysis

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Introduction

The Data Group has reviewed available analyses of distribution incident data and has performed additional analyses of both incident and leak data. This review and analysis have been designed to focus on identifying opportunities for improving the integrity of distribution pipelines, and to provide insights into approaches to improve the performance of these systems. The analysis has been structured to answer the following series of questions:

1. Which threats have greatest impact on distribution system safety?
2. Do data show whether threats are of increasing or decreasing concern?
3. Do data exist to support either focusing of new requirements on certain industry segments or excluding segments from new requirements?
4. Do data show any significant differences among states that may impact the findings from this Program?
5. Do the data show any trends in the amount of pipe constructed of materials more susceptible to leaking?

Analysis and findings related to each question are described below.

Which threats have greatest impact on distribution system safety?

Two types of data related to distribution pipeline system safety are reported by most jurisdictional operators: incident data and data on leaks removed or scheduled to be removed. Any event in which there is a fatality, an injury requiring hospitalization, property damage exceeding $50,000, or which in the operator's judgment is significant must be reported as an incident.[64] Events of lesser consequence may still be of concern, but have lower public safety significance than events meeting the above reporting criteria. For this reason, earlier studies tended to focus on incidents.

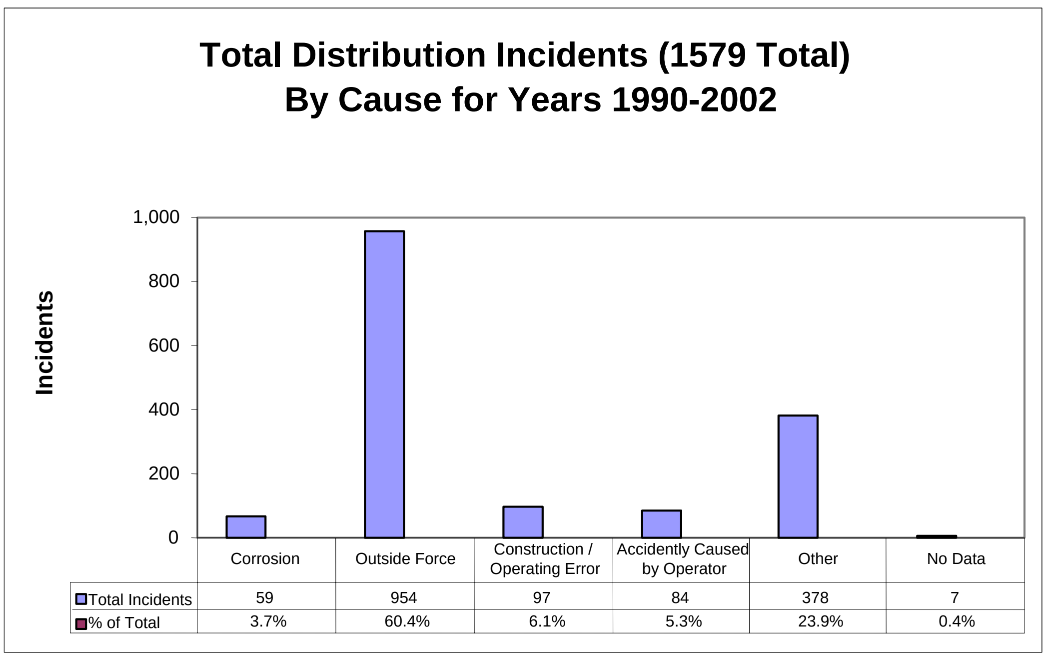
The American Gas Foundation (AGF) completed a study in 2004[65] that analyzed distribution system incidents that occurred during the period 1990-2002. During that period, operators were required to characterize reported incidents as resulting from one of five causes (corrosion, outside force, construction/operating error, accidentally caused by operator, and "other"). In early 2004, PHMSA revised its incident report form to require that distribution incidents be categorized according to seven major causes (corrosion, natural forces, excavation mechanical damage, other outside force damage, material/weld, equipment/operator error, and miscellaneous/unknown). These were

[64] Incident defined at 49 CFR 191.3. Reporting requirements at 49 CFR 191.5 and 191.9.
[65] American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure," January 2005

further subdivided into 25 sub-categories. PHMSA contracted with Allegro Energy Consulting to review all distribution incidents submitted during the period 1999-2003, and to re-categorize them according to the revised cause categories. The Allegro analysis[66] used information included on the incident report forms to better characterize incidents previously characterized as "other". It provides baseline trends consistent with new incident report causes.

Both the AGF and the Allegro analyses evaluated the relative importance of different incident causes. AGF determined that the predominant cause of distribution incidents over the 13 year period analyzed was outside force damage, accounting for 60 percent of all incidents. At the same time, AGF found that fully 24 percent of all incidents were categorized as "other".

Figure 1: Total Distribution Incidents by Cause 1990-2002



Source: Figure 3-5b from AGF Report

The Allegro analysis determined that 60 percent of the incidents categorized as "other" during the period 1999-2003 could be reclassified into one of the new causes, based on the narrative information submitted with each incident. This reduced uncertainty and improved understanding of the causes of a significant portion of reported incidents. In addition, the separation of the old outside force cause category into natural forces, excavation mechanical damage, and other outside force damage provided further insight into the root causes of the majority of reported incidents. The Allegro re-classification still identified excavation outside force damage as the largest single cause of distribution incidents, resulting in 38 percent of reported incidents. Allegro found, however, that

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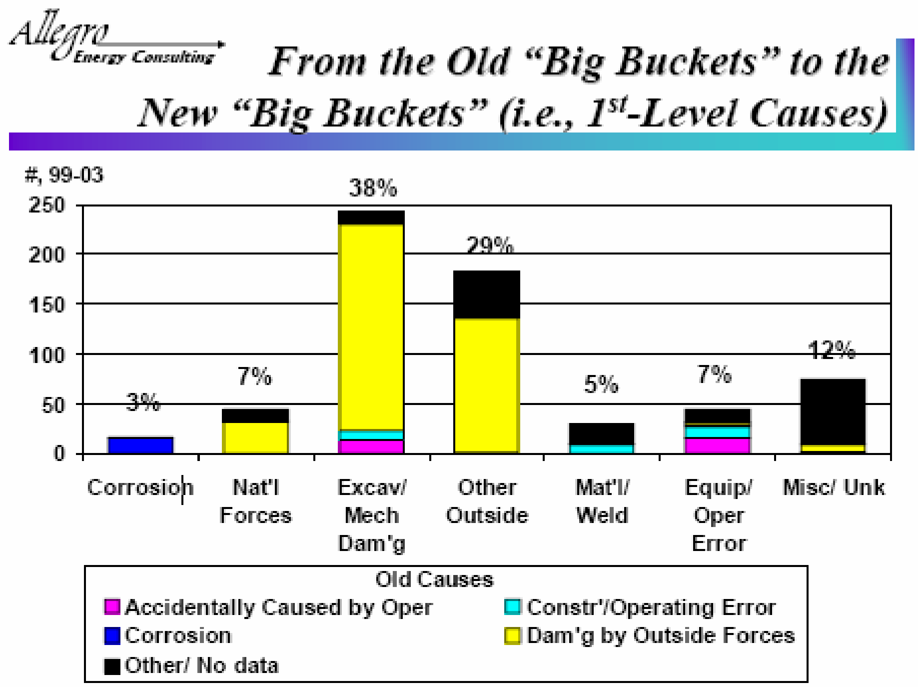
[66] Allegro Energy Consulting, "Safety Incidents on Natural Gas Distribution Systems: Understanding the Hazards," April 2005

other forms of outside force damage were also significant (29 percent). No other cause category produced more than 10 percent of incidents, with 12 percent not attributable (miscellaneous/unknown).

Figure 2: Re-Classification of Incidents by Allegro Study



Source: Allegro Report, page 20

Incidents do not occur frequently enough to be a useful metric for comparisons among operators, states, or regions of the nation. (Approximately 125 incidents were reported each year during the periods analyzed by AGF and Allegro). Reported leak data represents another source of information that is more useful for making such comparisons.

Leaks are the predominant mechanism by which distribution piping fails. Low-pressure pipelines, such as those in distribution systems, tend not to rupture but rather to fail by leaking[67]. This is a distinction from higher-pressure, transmission, pipelines in which failures occur by both leakage and rupture. A small fraction of distribution incidents have resulted when leaked gas migrates underground and accumulates in buildings, vaults, etc. and when the accumulated gas is subsequently exposed to an ignition source. Analyzing leak history thus provides information about where the potential for incidents initiated by leaks may exist.

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[67] In accordance to the discussion among the Data Group members, operators classify a distribution dig in as a leak not rupture. Transmission pipelines have a greater propensity for rupture; however; most transmission lines tend to also fail by leaking. In the context it is used in the transmission rule, the term "rupture" appears to mean a condition where pipelines fail because internal pressure exceeds pipe wall strength, which rarely occurs on low stress distribution lines.

AGF concluded that leak data from the PHMSA annual report database could not be used as an indicator of distribution system integrity, because data may be inconsistently reported and data do not include a complete inventory of leaks, but rather include only leaks that the operator repairs.[68] Despite these valid concerns, leak data are the only information available, other than incidents, to support evaluation of trends in distribution pipeline safety.

Operators must annually report all leaks removed by cause, for both mains and services. Operators must also report the number of known leaks scheduled for repair. Operators need not report known leaks that are not scheduled for repair, hence the annual report database does not include a complete inventory of all recognized leaks. The Data Group has used only data on leaks removed. Since the criteria for repairing leaks are not necessarily uniformly applied by all operators in reporting leak data, care should be exercised in drawing conclusions.

The cause categories for which leaks removed must be reported in the annual report changed in 2004 just as did those for incidents. Unlike the case of incident reports, operators do not provide narrative information that could be used to reclassify leaks reported on prior year reports. The Data Group thus focused on analyses of 2004 data to identify insights regarding the relative significance of threats.

For comparison purposes, incident data for 2004 was considered separately by the Data Group. In 2004, there were 171 gas distribution incidents reported to PHMSA. Figure 3 below shows the percentages of incidents by cause for both mains and services. Note that incidents in "other" service type include incidents that occurred other than in the distribution mains and services, such as meter set, meter set assemblies, pressure limiting and regulating facilities, and others. As in the AGF and Data Group analysis discussed above, involving longer time periods, excavation damage and other outside force damage are the leading causes of reported incidents.

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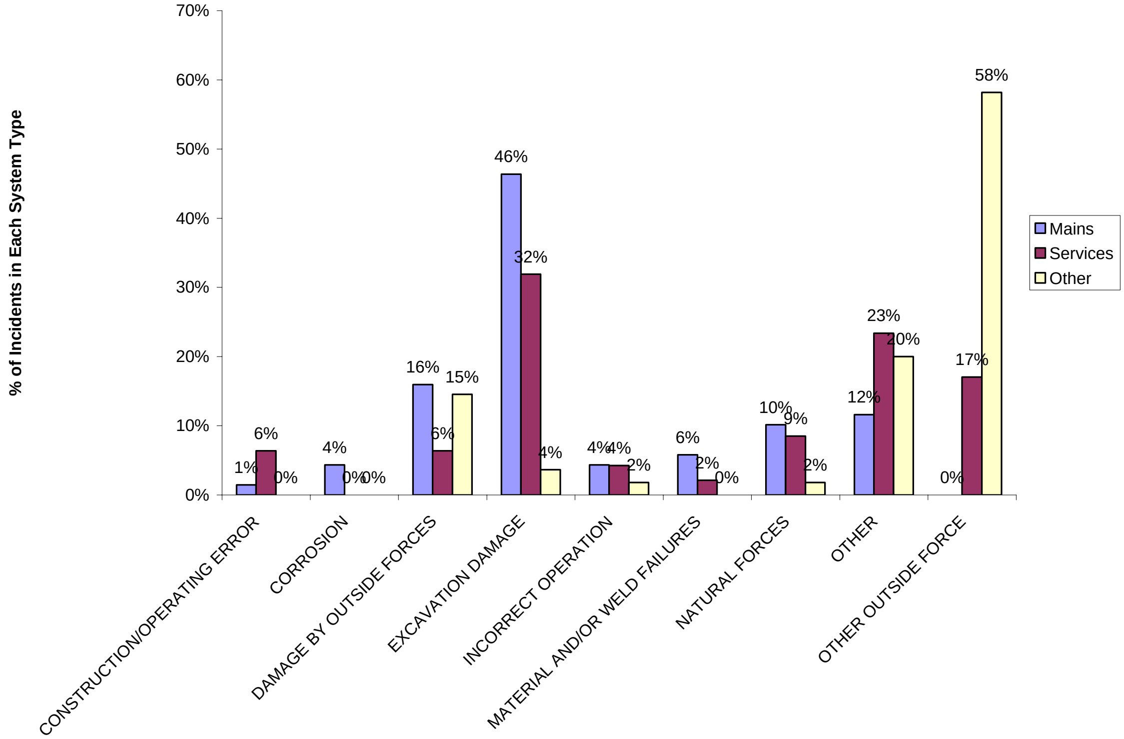
[68] AGF Report, page 8-2. See also Section 6 of the same report.

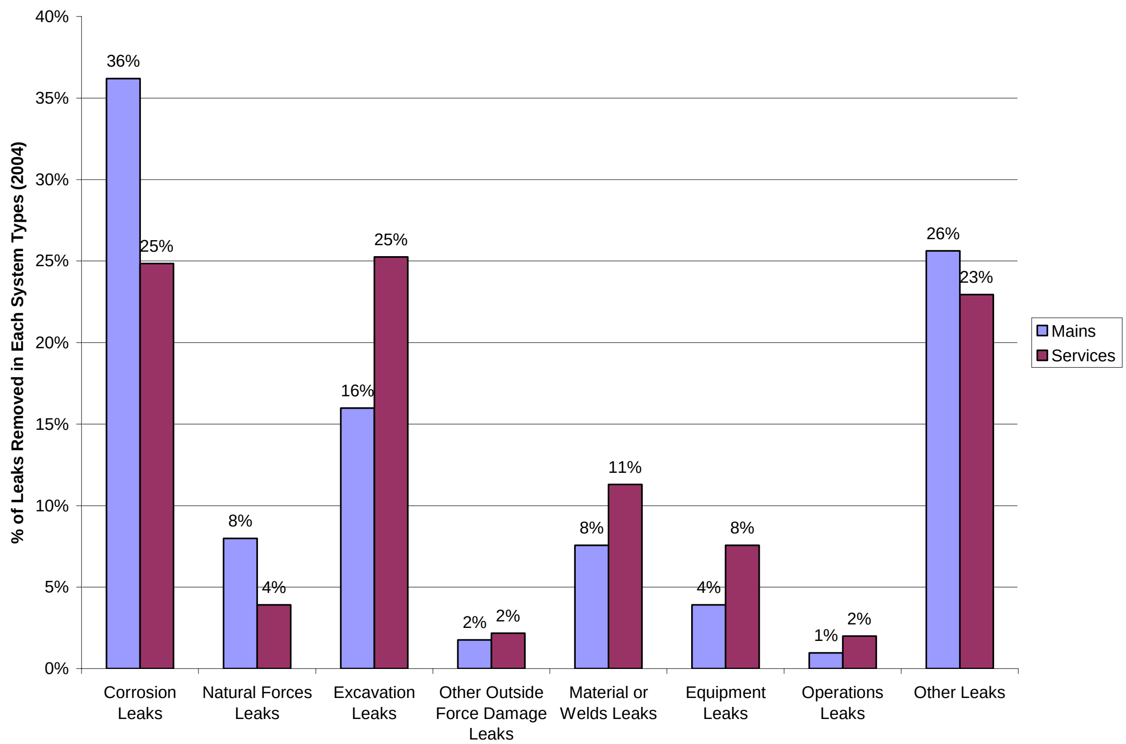
Figure 3: 2004 Gas Distribution Incidents by Causes and System Types



Source: 2004 Incident data.
"Other" includes incidents occurred in meter set, meter set assemblies, pressure limiting and regulating facilities, and others.

In 2004, operators reported a total of 171,347 leaks removed or eliminated on mains and 356,102 leaks on services. Figure 4 below shows the percentage of leaks removed from the gas distribution Annual Report submissions.

Figure 4: 2004 Leaks Removed by Causes and System Types

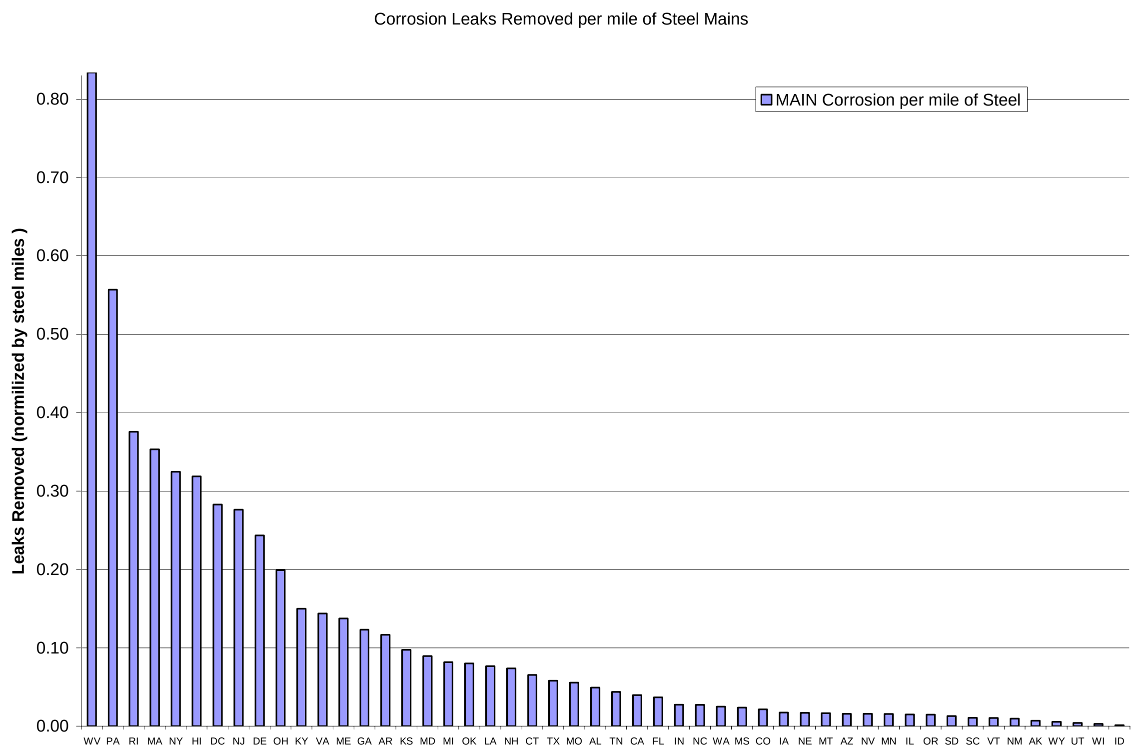


2004 Annual data reported as of 09/15/2005.

As is the case for incidents (see Figure 3), the 2004 data also indicate that excavation damage is a significant cause of leaks, accounting for 22 percent of all leaks removed. Other outside force, which was the cause for 29 percent of incidents evaluated in the Allegro study, and shown to be 17 percent of incidents reported in 2004, is a much less significant cause for leaks removed. It was cited as the cause in only 2 percent of reported leaks removed. Corrosion, on the other hand, is a much more significant cause for leaks removed, representing 36 percent on mains and 25 percent on services, compared to less than 5 percent of incidents.

An advantage to considering leak data is that leaks occur with high enough frequency to allow the data to be used to identify variations among states and regions. The Data Group evaluated the 2004 leak data by state for the threats of most significance. For the threat of corrosion, the variation among states in corrosion leaks removed per mile of steel main is shown in Figure 5. Note that leaks removed as reported in the Annual Report are not separated out by the material in which the leak occurred, however since corrosion only occurs on metallic pipe and the majority of metallic distribution pipe is steel, corrosion leaks removed per mile of steel main is a valid measure.

Figure 5: Corrosion Leaks Removed (Normalized by Miles of Steel Main) by States – 2004



2004 Annual data reported as of 09/15/2005.

The bars show the number of leaks removed per mile of steel mains. For leaks removed on steel mains, the variation is considerable. The state with the highest number of leaks removed per mile of steel main is West Virginia. The data indicate that corrosion leaks removed are a more significant issue in the Northeast (NY, NJ, RI, MA, ME) and the middle-Atlantic (PA, OH, DE, VA). Operators in the states of KY, AR, and GA also removed more than 12 corrosion leaks per 100 miles of steel main in 2004.

Hawaii appears to have significantly more corrosion leaks than most other states, but this result must be used with caution. The natural gas distribution system in Hawaii is very small, consisting only of 320 miles of steel main. The number of leaks reported is small, 102 corrosion leaks on mains but the small denominator results in the number per mile of steel main being high. It should also be noted that different operators have different philosophies on removing leaks, with some removing all identified leaks and others carefully categorizing the level of hazard and removing only leaks considered to be hazardous.

The results from the District of Columbia are similarly unusual. Again, the number of reported corrosion leaks is relatively small, 119 on mains, but the miles of steel mains is also small. The District of Columbia is unlike states in that it covers a small geographic area and is mostly urban. For states, the reported totals are a combination of urban, suburban, and rural experience. The results for DC could be comparable to results for other major cities, but data do not exist to allow this comparison. Therefore, analytical results for DC must be used with caution. Also, the reported data on leaks removed are for all mains and are not categorized by pipeline materials. The Table below shows the top 20 states for corrosion leaks removed per mile of their main lines. Table 1 also shows that the top states typically have a significant fraction of their mileage of steel mains that is not protected.

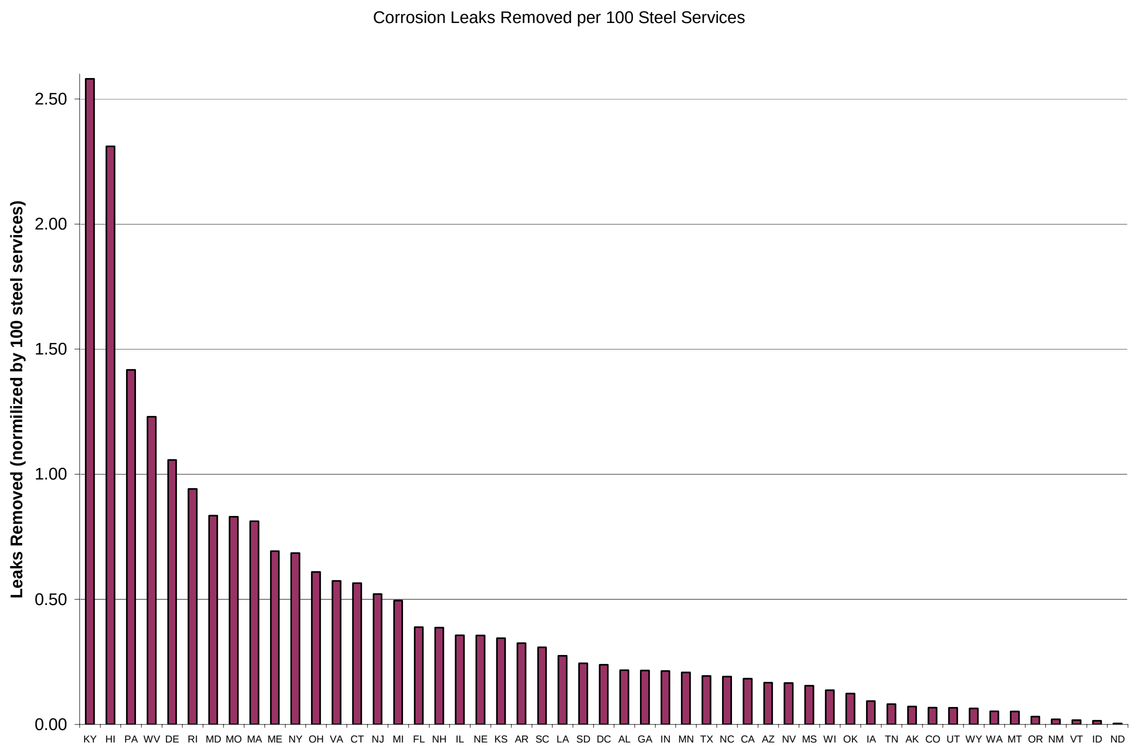
Table 1: Top States with Corrosion Leaks Removed in Distribution Mains (2004)

State	Corrosion Leaks Removed per Steel Main Mile	Steel Main Miles as a % of Total Main Miles	Unprotected Steel Main Miles as a % of Total Steel Miles
WV	0.83	51%	71%
PA	0.56	53%	45%
RI	0.38	41%	51%
MA	0.35	46%	37%
NY	0.32	52%	40%
HI	0.32	53%	48%
DC	0.28	35%	25%
NJ	0.28	43%	22%
DE	0.24	29%	11%
OH	0.20	60%	34%
KY	0.15	54%	12%
VA	0.14	37%	16%
ME	0.14	22%	5%
GA	0.12	44%	6%
AR	0.12	48%	9%
KS	0.10	53%	9%
MD	0.09	46%	11%
MI	0.08	46%	10%
OK	0.08	47%	12%
LA	0.08	63%	0%

Note that LA reported about 30 miles of unprotected steel mains. 5 additional states CA, TX, FL, MN, and NH have more than 10% of unprotected steel in their steel main miles.

The following graph shows the corrosion leaks removed on services normalized by the number of steel services. The table above, along with the display of these results in Figure 6, prompted the Data Group to determine whether a correlation exists between corrosion leaks removed and miles of unprotected main or number of unprotected steel services. That correlation, carried out using individual operator data, is discussed later in this section.

Figure 6: Corrosion Leaks Removed (Normalized by 100 Steel Services) by States



2004 Annual data reported as of 09/15/2005.

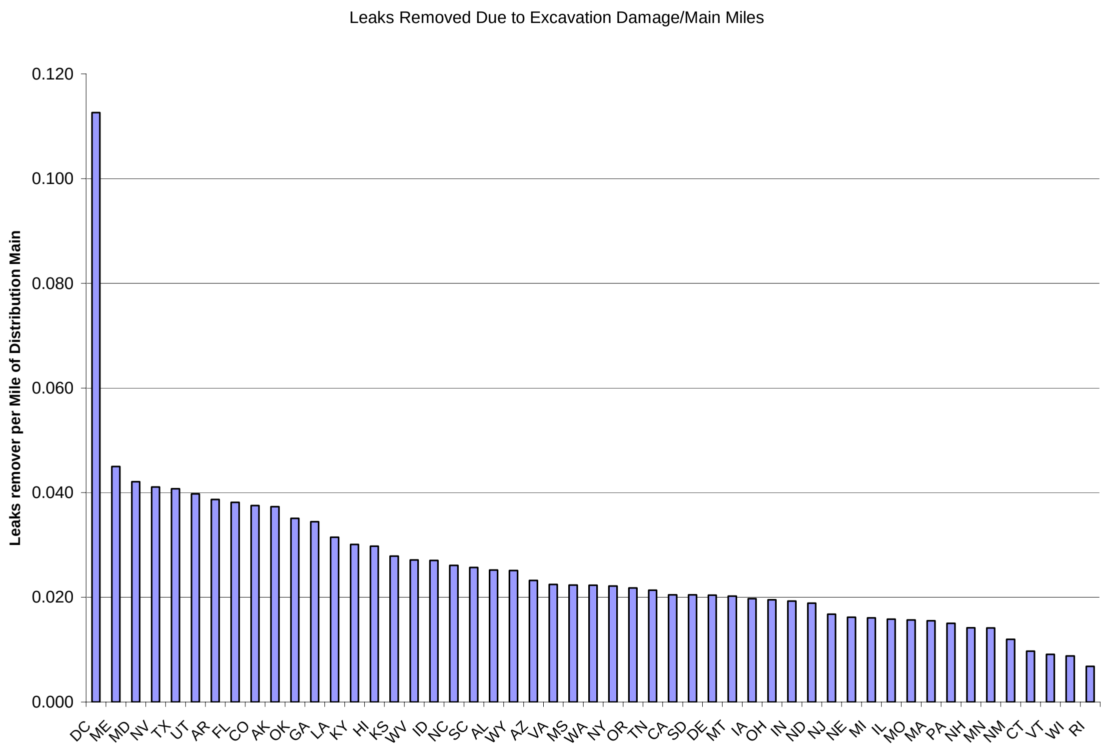
The following Table shows the top 20 States with corrosion leaks removed in steel services. Again as for mains, Table 2 below shows that the top states typically have a significant fraction of their services constructed from steel that is not protected.

Table 2: Top States with Corrosion Leaks Removed in Services (2004)

States	Corrosion Leaks Removed per 100 Steel Services	Steel Services a % of Total Services	Unprotected Steel Services as a % of Total Services
KY	2.58	38%	14%
HI	2.31	42%	58%
PA	1.42	32%	67%
WV	1.23	41%	57%
DE	1.06	26%	54%
RI	0.94	45%	80%
MD	0.83	32%	34%
MO	0.83	21%	17%
MA	0.81	36%	64%
ME	0.69	10%	56%
NY	0.68	33%	64%
OH	0.61	46%	61%
VA	0.57	22%	22%
CT	0.56	42%	51%
NJ	0.52	38%	17%
MI	0.50	27%	9%
FL	0.39	36%	26%
NH	0.39	31%	42%
IL	0.36	28%	3%
NE	0.36	40%	1%

Figure 7 shows leaks removed from distribution mains that were caused by excavation damage. For the threat of excavation damages, DC again appears to be an outlier, removing 134 leaks on 1190 miles of mains from this cause. Again, this result must be viewed skeptically. DC reported approximately twice as many leaks removed resulting from excavation damage to mains as did CT and DE (small states), but considerably fewer such leaks on services than either of those states.

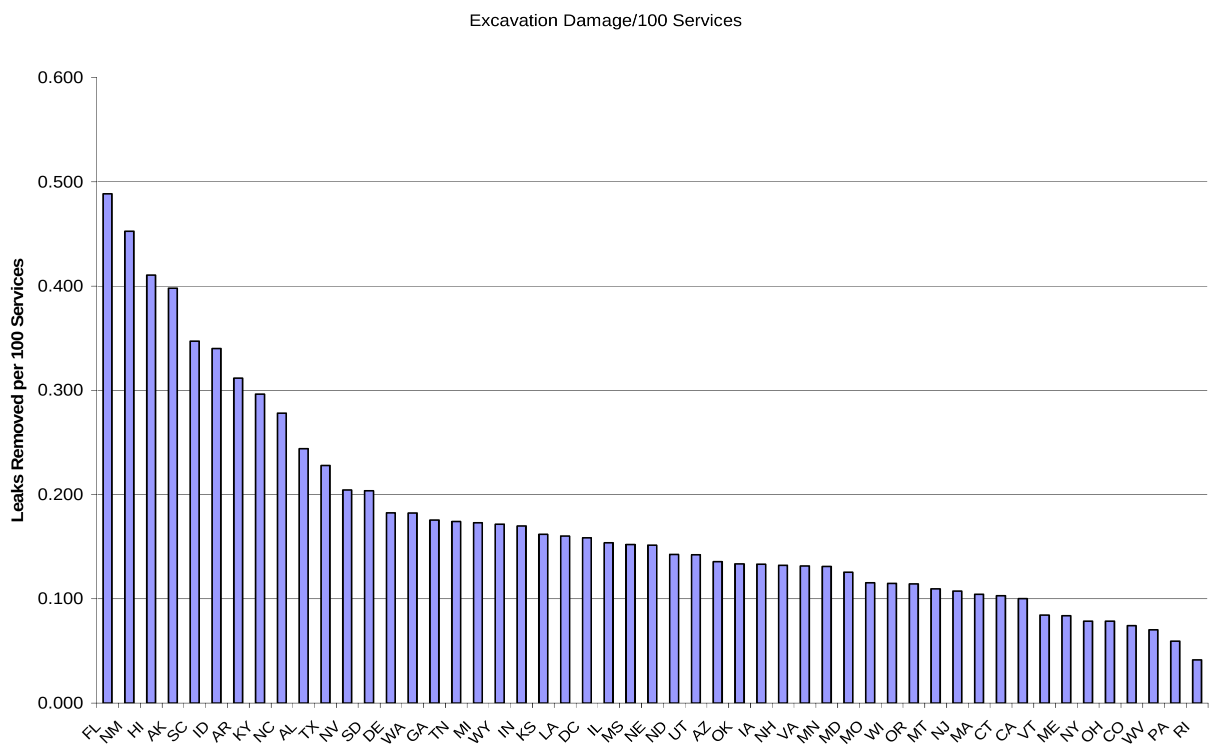
Figure 7: Excavation Damage Leaks Removed from Distribution Mains (Normalized by Main Miles) by States



2004 Annual data reported as of 09/15/2005.

The data in Figure 8 show that, after the top ten or twelve states, the number of leaks removed due to excavation damages on services (per 100 services) is relatively constant. There is more variability in the number of such leaks per mile of main, but no significant apparent regional variations.

Figure 8: Excavation Leaks Removed in Services (Normalized by 100 Services) by States



2004 Annual data reported as of 09/15/2005.

The data show that excavation damage caused a relatively higher number of leaks removed per 100 services for the top ten or twelve states. These top states include FL, NM, HI, AK, SC, ID, AR, KY, NC, AL, and TX. Numerous factors can affect the number of excavation leaks removed caused by excavation damage - including level of construction activity within a state. Therefore, these results should be used with caution.

While these results are interesting and may imply the need for further investigation, information supporting the reasons for exceptional rates of leaks removed is not generally available. As noted above, the criteria for repairing leaks are not necessarily uniformly applied by all operators, so care should be exercised in drawing conclusions.

As an aid in understanding leak causality, a simple linear regression model was run to assess whether the amount of unprotected steel mileage for each operator can help to explain the number of corrosion leaks removed in 2004. The analysis was performed for operators because there is insufficient data to run statistical regression at the State level. The model is explained below:

$y = \alpha + \beta x$

Where y is the corrosion leaks removed

x is the miles (or services) of unprotected steel

Two models were run, one with corrosion leaks removed from mains as the dependent variable and miles of unprotected steel as explanatory variable; and one with corrosion leaks removed from services as the dependent variable and number of unprotected steel services as explanatory variable. The results of the regression analysis (with t-statistics in the parenthesis below - higher values of the t-statistic imply stronger correlation) are presented below.

Model 1: Corrosion Mains = 18.04 + .48 (UP_miles_steel_mains)
(4.28) (42.98)

Model 2: Corrosion Services = 29.68 + .009 (UP_Steel_Services)
(3.97) (33.88)

The R-squares for Model 1 is 0.56 while for Model 2 is 0.45. (The strength of a model's ability to explain a phenomenon increases as the R-square increases). Note that if cast iron pipe mileage is added as an explanatory variable in the first model, the correlation improves slightly (the value intercept goes down and R-square value increases). However, the second model's explanatory power does not improve statistically with inclusion of cast iron services as an additional explanatory variable.

Therefore, the number of corrosion leaks removed from mains correlates well with the amount of unprotected steel present in the system. Statistical analysis confirms this correlation. The strength of the correlation in Model 2 (between corrosion leaks removed from services and number of unprotected steel services) is somewhat less, but the number of unprotected steel services is still statistically significant in explaining the number of corrosion leaks removed in the service lines. It should be noted that while the models appear to demonstrate a stronger correlation between corrosion leaks removed for miles of unprotected main, (the percent of unprotected steel mains has an apparently stronger (0.48) relationship to the rate of corrosion leaks removed on mains and an apparently weaker (0.009) relationship to the rate of corrosion leaks repaired on services), this is not true since the number of services is approximately a factor of 63 greater than the number of miles of main.

In summary, analysis of the data reveals that the threats of principal concern for distribution integrity are excavation/mechanical damage, outside force, and corrosion. The latter is a principal cause of distribution leaks (removed), but has resulted in relatively fewer incidents. The analysis also demonstrates that number of leaks removed correlates well with miles of unprotected steel pipe and number of services.

The Data Group did not consider "other outside force damage" and its variation among states.

Do data show whether threats are of increasing or decreasing concern?

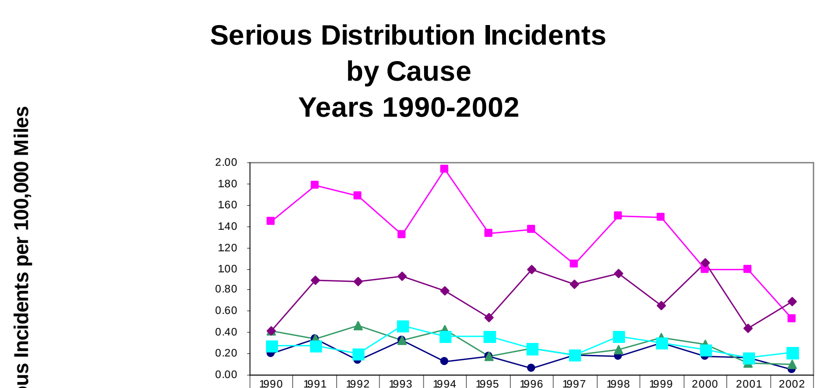
Analyzing the trends for distribution incidents from various causes was a principal purpose of the AGF study. As described above, this study considered incidents reported to PHMSA by distribution system operators from 1990 to 2002. The study analyzed the trend for each of the five incident causes reported over that period, subjecting each to a statistical test[69] to determine if apparent trends were significant. For most of its analysis, the study focused on incidents in which fatality or injury occurred (which the study referred to as "serious incidents"), representing 601 of the 1,579 incidents reported over the analyzed period. AGF also superimposed lines on the bar graph data to illustrate the trends and estimated reductions/increases in incidence between 1990 and 2002 by comparing the endpoints of those lines. (The trend lines were determined by regression analysis. The significance noted in the AGF report relates to the direction not to the magnitude of the trends. For example, the M-K statistical test showed that there was a downward trend in serious incidents caused by outside force damage at a 95 percent confidence level. The AGF trend line estimated that the rate of these incidents declined 58 percent over the period analyzed. The 58 percent estimate is derived from a best-fit curve based on the data but is not, itself, accurate to a 95 percent confidence level).

The AGF study concluded that there was not a statistically-significant downward trend in *total incidents* reported per 100,000 miles from 1990 to 2002 at a 90 percent confidence level.[70] By contrast, the trend for incidents involving fatality or injury (i.e., "serious incidents") was downward at a 95 percent confidence level over the same period.[71] AGF concluded that there were downward trends, at a 95 percent confidence level, for serious incidents caused by outside force and construction/operating error. The trend was downward at a 90 percent confidence level for serious incidents caused by the threats of corrosion and accidentally caused by operator. The trend was indeterminate for those serious incidents categorized as "other". The figures describing these trends from the AGF report are reproduced in Figure 9 below.

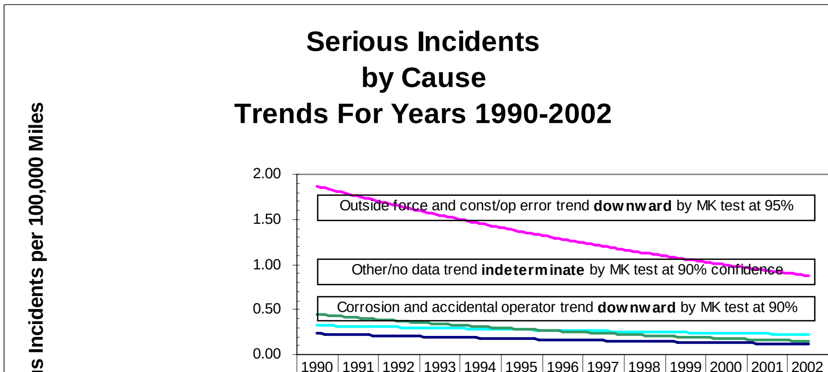
[69] The Mann-Kendall (M-K)
[70] AGF Report, Appendix B, Figure B1, page B-21.
[71] AGF Report, Appendix B, Figure B5, page B-28.

Figure 9: Serious Distribution Incidents by Cause: AGF Study

	Corrosion	Outside Force	Construction / Operating Error	Accidentally Caused By	Other	No Data
Serious Incidents	39	280	59	59	160	4
% of Total	6.5%	46.6%	9.8%	9.8%	26.6%	0.7%



	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Corrosion	0.21	0.34	0.13	0.33	0.12	0.18	0.06	0.18	0.18	0.30	0.18	0.17	0.05
Outside Force	145	179	168	132	194	133	137	104	150	148	100	0.99	0.53
Construction / Operating Error	0.41	0.34	0.47	0.33	0.42	0.18	0.25	0.18	0.24	0.36	0.29	0.11	0.11
Accidentally Caused By Operator	0.28	0.28	0.20	0.46	0.36	0.36	0.25	0.18	0.36	0.30	0.23	0.17	0.21
Other / No Data	0.41	0.89	0.88	0.93	0.79	0.54	100	0.86	0.96	0.65	106	0.44	0.69

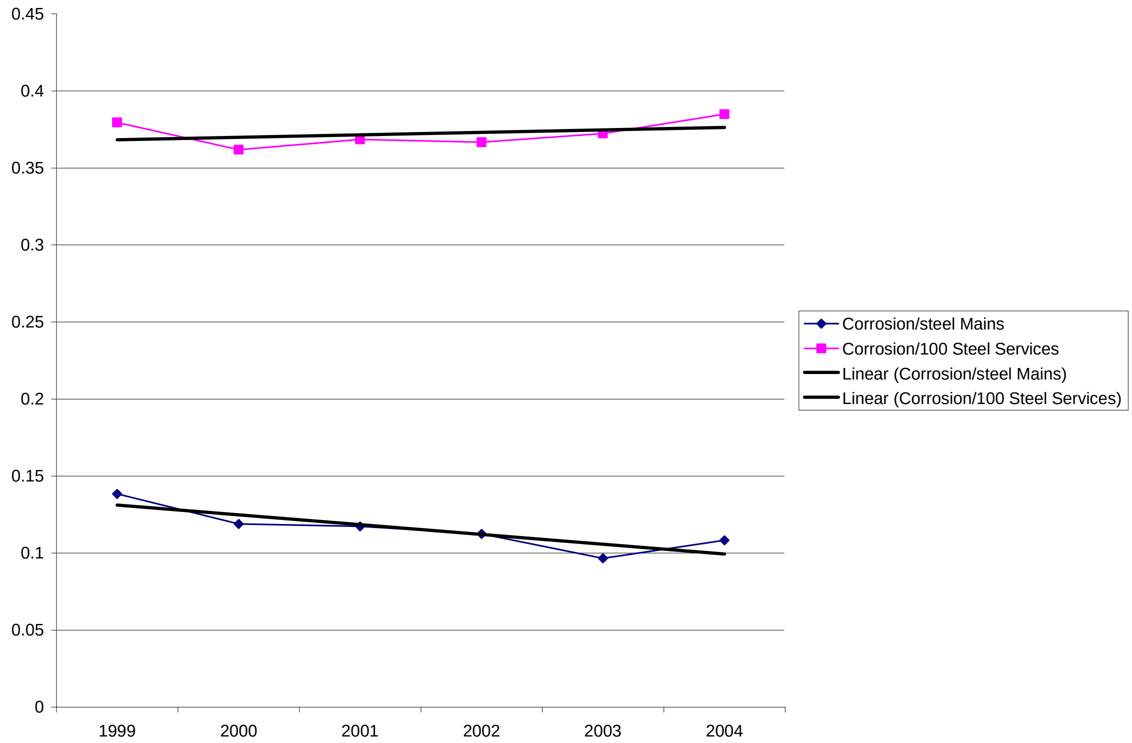


	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Corrosion	0.21	0.34	0.13	0.33	0.12	0.18	0.06	0.18	0.18	0.30	0.18	0.17	0.05
Outside Force	1.45	1.79	1.68	1.32	1.94	1.33	1.37	1.04	1.50	1.48	1.00	0.99	0.53
Construction / Operating Error	0.41	0.34	0.47	0.33	0.42	0.18	0.25	0.18	0.24	0.36	0.29	0.11	0.11
Accidentally Caused By Operator	0.28	0.28	0.20	0.46	0.36	0.36	0.25	0.18	0.36	0.30	0.23	0.17	0.21
Other / No Data	0.41	0.89	0.88	0.93	0.79	0.54	1.00	0.86	0.96	0.65	1.06	0.44	0.69

Source: Figure B16. Serious Incidents by Cause (from AGF Report)

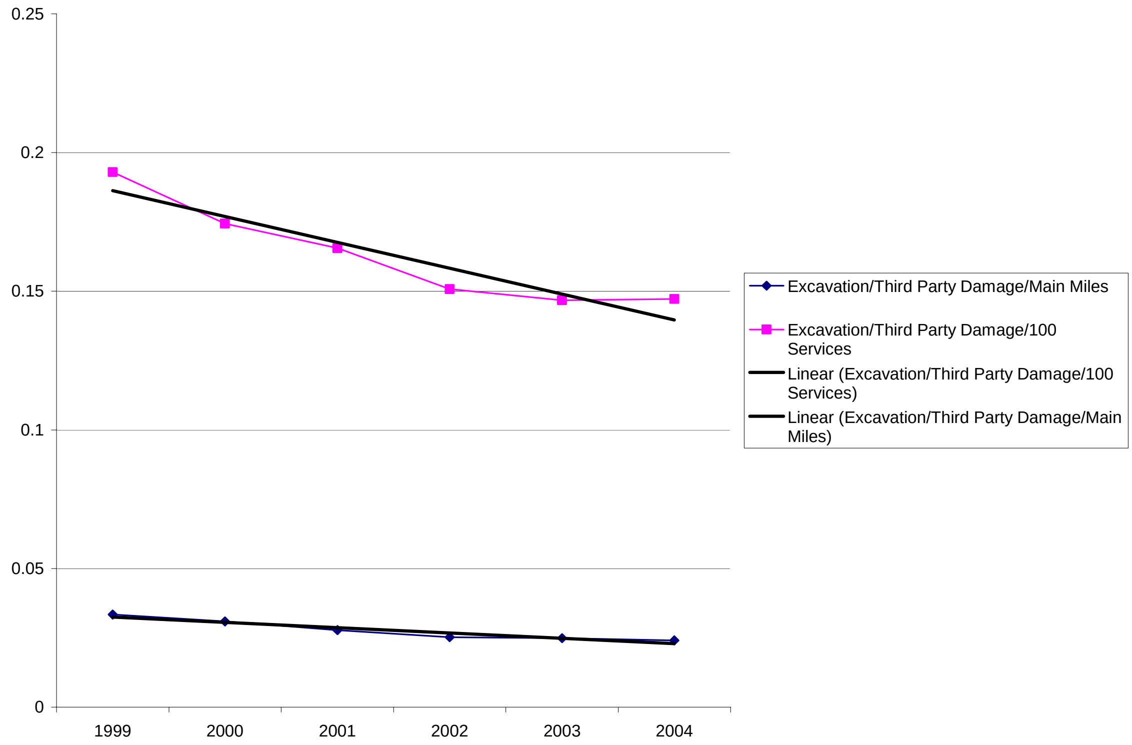
Leakage data for the period 1999-2004 has been evaluated to identify significant trends. The results are shown on Figures 10 and 11.

Figure 10: Trends in Corrosion Leaks Removed in Steel Main Miles and Steel Services



Source: 2004 Annual data reported as of 09/15/2005.

Figure 11: Trends in Excavation Damage Leaks Removed in Main Miles and Services



2004 Annual data reported as of 09/15/2005.

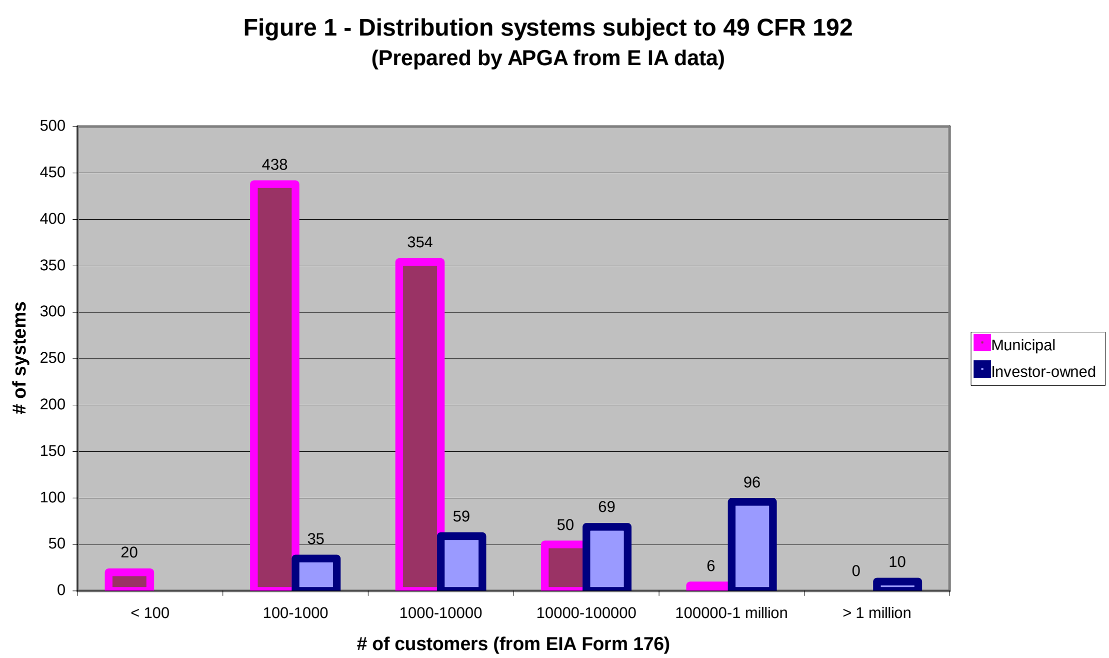
(Note that due to the changes in the Annual Distribution Forms in 2004, data for 1999-2003 for the categories in the latter graph may or may not be comparable. The third party damage category was used for 1999-2003 data as a proxy for excavation damage. Excavation damage was used for the 2004 data point.). The Data Group discussed how best to correlate excavation damage and concluded, as did the Excavation Damage Prevention Group (EDPG), that the number of requests to locate facilities seems to be the best independent variable for correlation. Related analysis has been carried out by the EDPG.

The data on leaks removed do not show a significant trend for corrosion leaks (see Figure 10.) . The trend for excavation damage on mains appears to be downward. There is also a downward slope for excavation-induced leaks on services, although the amount of decrease makes it unlikely that this trend would be statistically significant. (Statistical tests were not applied to leak trend data).

Do data exist to support either focusing of new requirements on certain industry segments or excluding segments from new requirements?

There is significant diversity among distribution pipeline operators. This raises questions as to whether it is necessary, appropriate, or efficient to apply any new requirements to assure distribution system integrity to all operators in the same manner. APGA prepared the following chart, based on data from the Energy Information Administration (EIA), in support of the PHMSA Report to Congress on distribution integrity.

Figure 12: Number of Systems in Distribution: APGA Study



This graph does not show master meter operators or liquid propane (LP) gas operators that are regulated as distribution systems, since EIA does not report data on those groups. There are thousands of master meter operators, some with only a few customers but most with fewer than 100. LP gas operators become subject to Part 192 when they serve 10 or more customers, and there are probably around 100 of those operators, virtually all serving fewer than 100 customers.

The Data Group looked to the available data to try to determine whether small operators might reasonably be subjected to different integrity management requirements.

The analysis considered 2004 leaks removed as reported by operators in their Annual Reports. There was no consensus among the data group members on the definition of the "large" versus "medium" or "small" operators for use in assessing whether the size of the operators could justify different integrity management process features. Based on the discussion in the group, operators were categorized into 5 groupings based solely on the miles of mains they operate (as reported on the 2004 Annual reports). To compare the grouping based on main miles only, a second grouping was identified based on number of services as reported on the 2004 Annual reports. The groupings shown in the Tables 3 and 4 were; therefore, not developed based on statistical clustering method.[72]

Table 3. Based on miles of mains – 5 groups

	Groups by Miles of Mains					
	10,001-100,000	**5,000 - 10,000**	**1,000-4,999**	**999-500**	**<500**	
Number of Operators	25	31	115	72	1,189	
% of Unprotected Steel	45%	24%	26%	2%	3%	100%
% of Protected Steel	44%	19%	26%	4%	7%	100%
% of Miles of Mains	43%	20%	26%	4%	7%	100%
% of Number of Services	47%	21%	25%	3%	4%	100%
Median Miles of Mains	16,480	7,206	2,528	660	31	
Mean Miles of Mains	19,406	7,228	2,580	677	71	
Median Number of Services	923,515	408,783	112,163	22,010	766	
Mean Number of Services	1,158,161	405,738	133,432	23,681	2,108	
Corrosion Leaks Removed/Steel Miles	0.071	0.176	0.135	0.076	0.069	
Corrosion Leaks Removed/Steel Services	0.003	0.004	0.005	0.003	0.004	
Excavation Leaks Removed/Main Miles	0.026	0.021	0.024	0.026	0.019	
Excavation Damage Removed/Services	0.001	0.002	0.001	0.002	0.002	

[72] A clustering analysis was conducted based on the two variables, miles of mains and number of services together and based on each variable individually. However, there was no consensus on the result of the clustering as a large number of operators (based on strictly bivariate or univariate clustering) were placed on a single group which could not be identified as “small” operators by the group.

Table 4. Based on number of services – 9 Groups

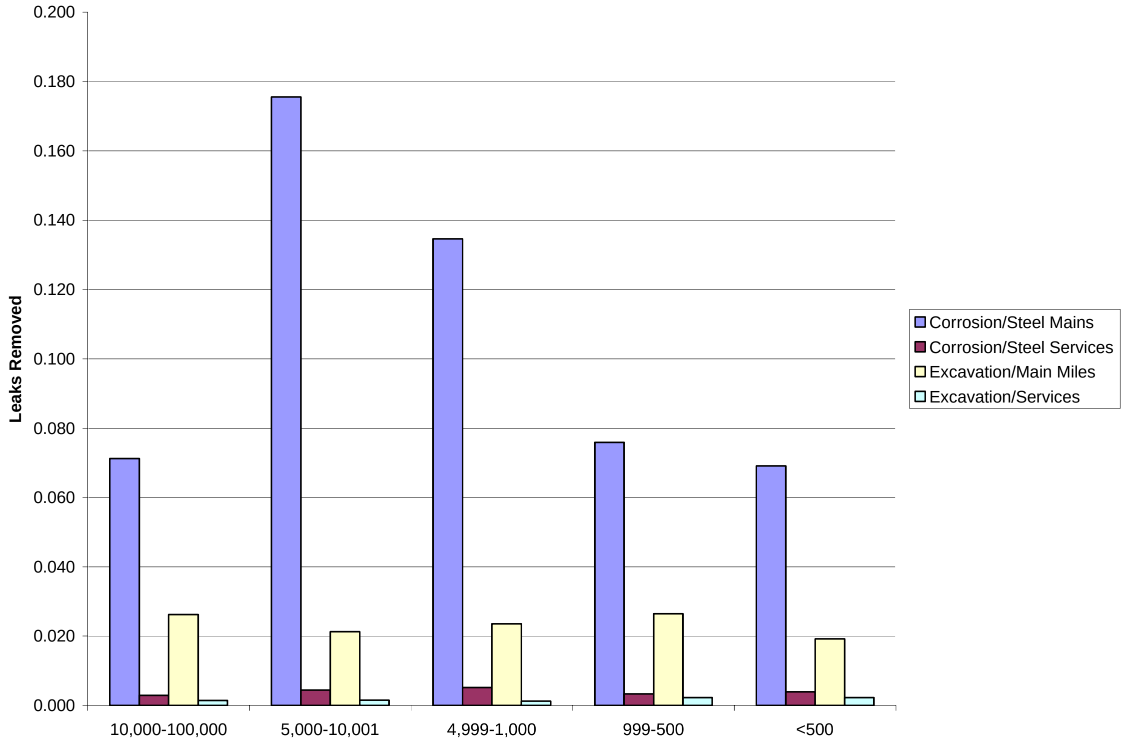
	Groups by Number of Services									
	> 1 million	**100,001 – 1 million**	**10,001-100,000**	**5,001-10,000**	**4,001-5,000**	**2,001-4,000**	**1,001-2,000**	**501-1,000**	**<500**	
Number of Operators	11	109	154	103	49	141	189	227	449	
% of Unprotected Steel	36%	53%	9%	1%	0%	0%	0%	0%	1%	100%
% of Protected Steel	27%	54%	11%	2%	1%	1%	1%	1%	2%	100%
% of Miles of Mains	26%	54%	12%	2%	1%	1%	1%	1%	1%	100%
% of Number of Services	33%	55%	9%	1%	0%	1%	0%	0%	0%	100%
Median Miles of Mains	27,038	4,568	699	247	110	94	44	25	10	
Mean Miles of Mains	27,046	5,646	915	272	137	109	57	31	38	
Median Number of Services	1,459,761	264,882	26,738	7,013	4,432	2,773	1,375	671	191	
Mean Number of Services	1,825,943	309,263	35,096	7,205	4,462	2,867	1,416	707	213	
Corrosion Leaks Removed/Steel Miles	0.086	0.132	0.082	0.079	0.046	0.059	0.053	0.040	0.020	
Corrosion Leaks Removed/Steel Services	0.004	0.004	0.003	0.004	0.002	0.004	0.005	0.003	0.010	
Excavation Leaks Removed/Main Miles	0.026	0.023	0.027	0.016	0.017	0.024	0.018	0.011	0.012	
Excavation Damage Removed/Services	0.001	0.001	0.002	0.002	0.002	0.002	0.005	0.001	0.006	

Table 3 shows that nearly 83 percent of distribution system operators (1160 out of 1401) operate less than 500 miles of main. These operators have less than 10 percent of total mileage and only 4 percent of total services. The median main mileage for these operators is 31 miles, meaning that 580 companies/municipalities operate less than 31 miles of main.

Table 4 shows the same set of operators grouped into nine categories by number of services. The last group, representing operators with fewer than 500 services, represents 32 percent of all operators, operates less than 2 percent of all main mileage, and less than 1 percent of total services.

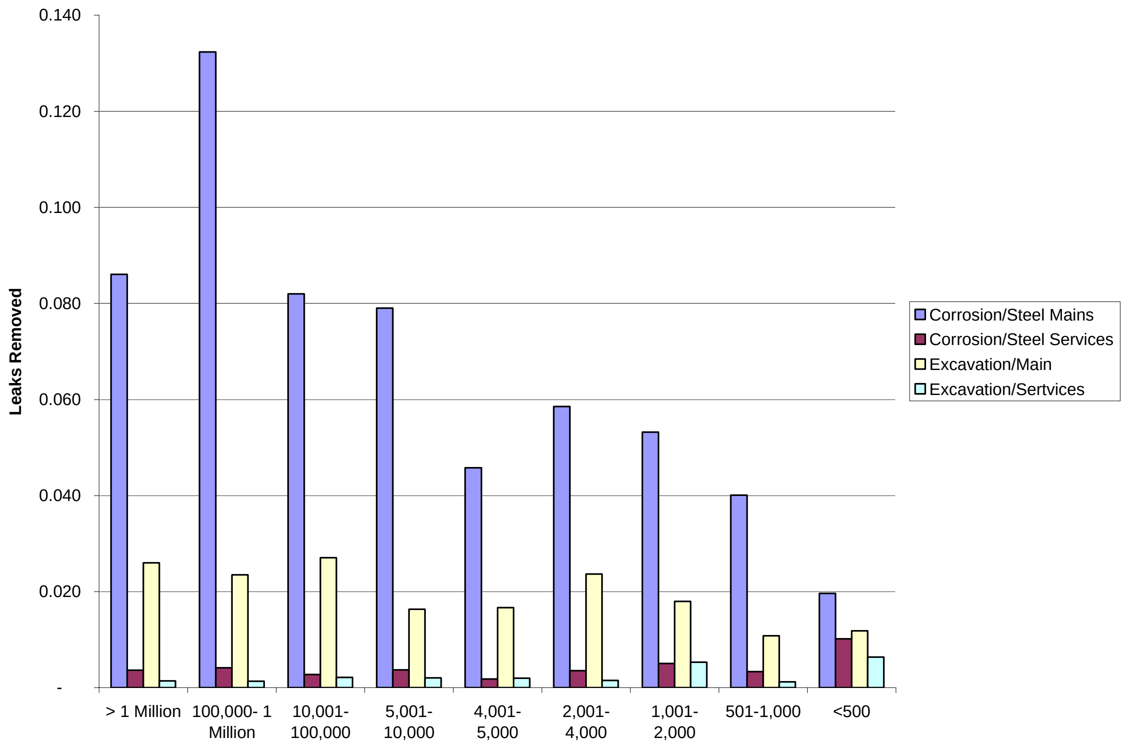
The last four rows in each table represent the number of leaks removed reported by operators in each group due to corrosion and excavation damage per mile of main (limited to steel mains for corrosion) and per service. This information is displayed graphically on Figures 13 and 14.

Figure 13: Corrosion and Excavation Damage Leaks Removed in Steel Main Miles and Steel Services by 5 Groups



Source: PHMSA 2004 Annual Distribution Data as of 9/15/2005

Figure 14: Corrosion and Excavation Damage Leaks Removed in Steel Main Miles and Steel Services by 9 Groups



Source: PHMSA 2004 Annual Distribution Data as of 9/15/2005

The data do not demonstrate any significant variations among different size operators using the two broad classification systems - groups based on mains and groups based on services and among individual sub-group members (5 sub-groups in Group based on main miles and 9 sub-groups based on number of services)   Given the acknowledged variability in how operators report leaks removed, it is not clear whether the visually observed variation is sufficient to justify a different approach to integrity management for these operators.

Master meter and LP gas operators are not required to file annual reports; therefore, there are no data that can be analyzed to see whether these operators have demonstrated significantly better or poorer performance than local distribution company operators. The available data are simply not adequate to determine if these smallest operators should be treated differently in terms of integrity management requirements. PHMSA' gas incident database does not have information to simply determine how many incidents occurred for the LP operators or for master meter operators since operator type is not collected in the form. Such an analysis would require incident-by-incident review and has not been undertaken by the Data Group.

Do data show any significant differences among states that may impact the findings from this Program?

The Data Group considered comparing incident frequency to identify states with exceptional performance; however several factors made identifying differences among states difficult. Variations among states in incident frequency or leak rates for most threats (other than excavation damage) would reflect the unique character of distribution systems in those states or other local environmental factors (e.g., weather or seismicity). Differences in construction activity would influence excavation damage. In addition, the relatively small number of incidents that occur in an individual state would make comparative analysis of incident frequency statistically meaningless. Therefore, limited value would be derived from detailed comparative analysis of incident or leak removal data among states. State-mandated replacement programs could, however, affect trends in leaks in pipes constructed from old materials such as cast iron or dated plastics.

The one area of investigation that could be useful is to look at year-to-year trends in leaks removed associated with states in which innovative or aggressive programs are in place to minimize excavation damage or leaks in pipes constructed from old materials such as cast iron or dated plastics. Effective programs would be indicated by decreasing trends in the removal rate for leaks by material of construction. These data are not currently available. Such an analysis has been undertaken by the excavation damage prevention group for excavation damage prevention programs.

Do the data show any trends in the amount of pipe constructed of materials more susceptible to leaking?

Several operators and the states in which they operate have recognized that unprotected steel pipes and cast iron may have higher rates of leak removal and have begun active replacement programs for pipe constructed from those materials. The figures below shows that there is a downward trend in the unprotected bare steel miles of main as well as for unprotected bare steel services while the trend is somewhat flat for unprotected coated pipes. The evaluation of annual data indicates potential reporting problems with cast iron mileage information. Periodic analysis of these data would highlight problem areas (i.e., operators reporting apparent increased use of cast iron), and corrections to the data could be sought.

Figure 15: Trends in Unprotected Steel Mains

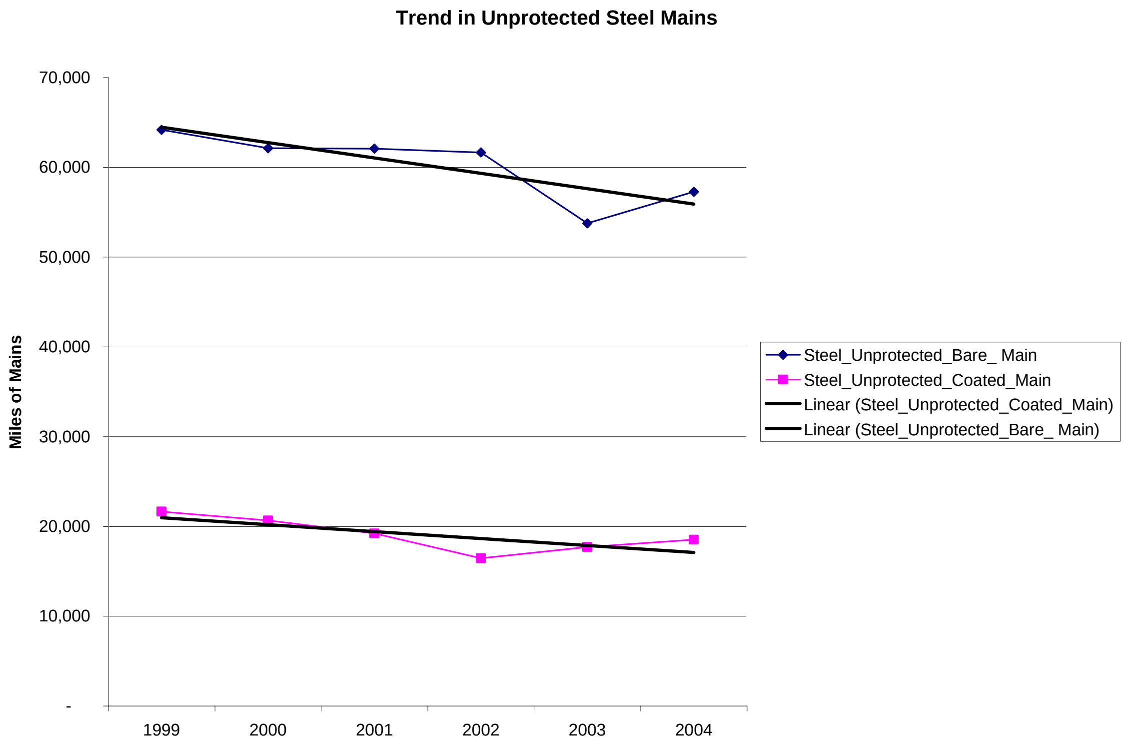


Figure 16: Trends in Unprotected Steel Services

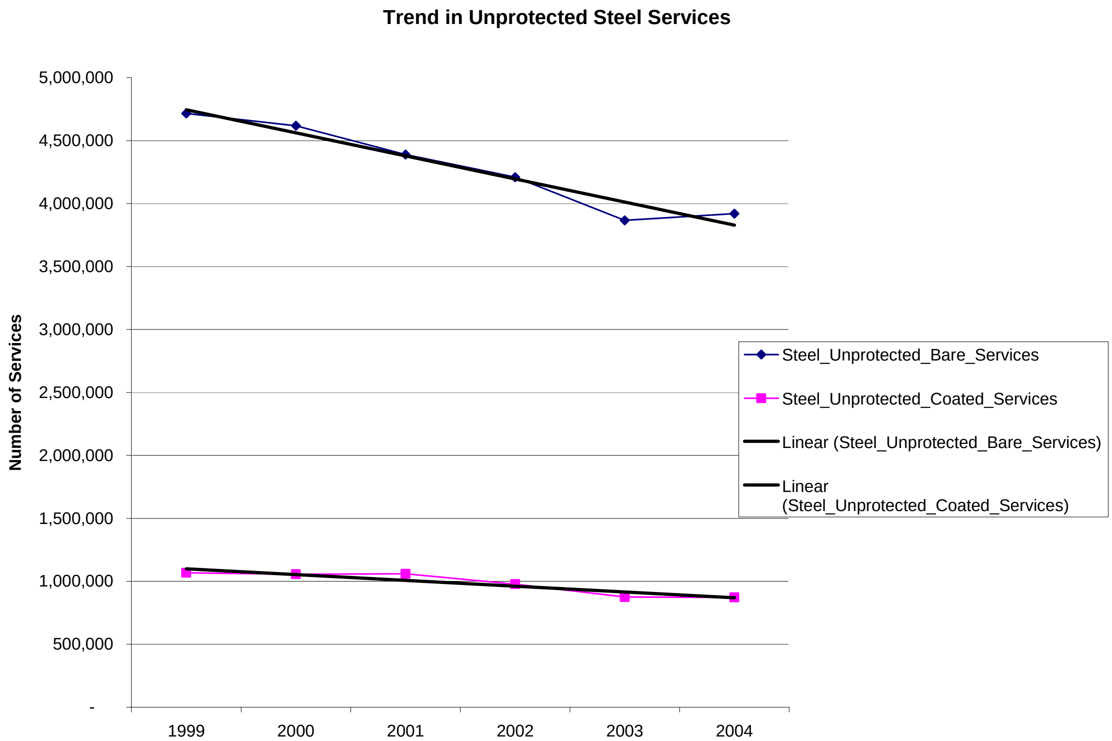


Exhibit B
Performance Baseline and Changes to Reported Data

Introduction

Characterizing the performance baseline for distribution systems is useful for understanding the current situation against which trends can be compared to evaluate the impact of future improvements. The baseline developed for distribution integrity management needs to reflect the metrics that operators agree, or are required, to track/report in future years. Therefore, the description of the baseline presented here may need to be reviewed and updated to reflect the metrics developed in the DIMP.

There are four types of information that could potentially be used to characterize the baseline for distribution pipeline integrity:

- DOT reportable incident statistics
- Data on leaks removed
- Information on system physical characteristics (e.g., miles of materials having a higher potential to leak such as unprotected steel)
- Maturity of integrity management processes.

The group also considered the potential use of Safety-Related Condition Reports and concluded that since there are so few for distribution systems, these would not be useful in characterizing the performance baseline.

Although each of the four types of information enumerated above could be useful in defining the baseline, three caveats need to be recognized. First, much of the information supporting characterization of the baseline (e.g., monitored leaks, process maturity) is accessible only to individual operators. Second, inconsistency in the categorization of leaks makes comparison between individual operators and an established baseline meaningless. Finally, while incident information for the industry as a whole has some meaning, incidents occur sufficiently infrequently that information for individual operators or even for individual states cannot meaningfully be compared to a nation-wide baseline.

On August 30, 2005, the DIMP Data Group discussed these four types of information by developing answers to the following set of questions.

1. What is the current source of the data?
2. What are the current data (fields)?
3. What metrics can be developed from the data?
4. What are the limitations of conclusions that can be drawn from these metrics?
5. Can these metrics serve as a performance baseline (are certain metrics invalid using historical data)?
6. Can these become valid metrics by changing future data collection (scope or guidance)?

The discussion of the final question supports identification of potentially useful changes to currently reported data. The results of these discussions are presented below.

Incident Data

1. *What is the current source of the data?*

Incident Report - Gas Distribution Systems (PHMSA F 7100.1)

2. *What are the current data (fields)?*

Incident causes and consequences, pipeline physical characteristics

3. *What metrics can be developed from the data?*

Importance of causes for services and mains, trends in causes, physical characteristics of systems experiencing incidents with various causes, when combined with information from Annual Reports - normalized incident rates

4. *What are the limitations of conclusions that can be drawn from these metrics?*

- Excessive reliance on "miscellaneous" cause category
- Limited number of incidents - little can be inferred from incident statistics at the individual operator or state levels
- Quality of data is better for more severe incidents (those involving fatalities or injuries)
- Inconsistent and likely over-reporting of incidents involving property damage or the judgment of the operator

5. *Can these metrics serve as a performance baseline (are certain metrics invalid using historical data)?*

- Cause categories changed in 2004, trends involving earlier data require significant analysis to match current categories
- Limited number of incidents (small sample size) means that trends and the relative importance of causes at a national level can be meaningful, but those at the state level or operator level are of questionable value

6. *Can these become valid metrics by changing future data collection (scope or guidance)?*

- Useful to add a check box on whether the regulations clearly require reporting or whether the report is submitted at the discretion of the operator (need criteria if check box is added)

- Should carefully review DIRT reporting forms to determine whether additional information should be added when the cause is excavation damage
- Data Group strongly suggests that the "miscellaneous" category be significantly reduced - perhaps by evaluating the causes associated with these incidents and appropriately expanding the cause category list

Leakage Data

1. *What is the current source of the data?*

Annual Report for Gas Distribution Systems (PHMSA F 7100.1-1)

2. *What are the current data (fields)?*

Leaks removed by cause for mains or services, number of known system leaks at end of year scheduled for repair

3. *What metrics can be developed from the data?*

Leaks eliminated by cause for mains and services, leaks eliminated normalized by miles of main and number of services, trends in leaks eliminated by cause normalized by miles of main and number of services

4. *What are the limitations of conclusions that can be drawn from these metrics?*

- Individual state data incomplete prior to 2004
- Cannot tie leaks eliminated to pipe material, diameter or age
- Leaks are graded differently by different operators
- Truly hazardous (requiring immediate attention) leaks are not reported separately, but are lumped in with other eliminated leaks - the Group believes that the hazardous leaks removed may be a more appropriate indicator of public safety and the attention should be focused here.
- Leak reporting for those repaired and those eliminated by pipe replacement are not treated consistently (replacement of a single segment may eliminate numerous leaks)
- Leak data are reported inconsistently on leaks that are monitored
- Leaks reported as scheduled for repair are inconsistently reported, and are often not eliminated during the following year

5. *Can these metrics serve as a performance baseline (are certain metrics invalid using historical data)?*

Within the limitations cited above, some baseline measures can be developed from available data

6. *Can these become valid metrics by changing future data collection (scope or guidance)?*

Consensus was reached on the following:

- Leak reports should be revised to require pipe material and presence of protection (i.e., coating, cathodic protection) as well as leak cause
- Hazardous leaks (those requiring immediate attention) should be reported as a subset of all leaks eliminated
- Guidance is needed to address inconsistencies in data assembly and reporting noted in item #4 above

The Data Group was not able to reach consensus on the need for any additional national-level leak-related reporting requirements. Members were divided on whether data on non-hazardous leaks were in any way significant to safety at the national level or are properly a reflection of the effectiveness of individual operator leak management practices.

The Group referred the following opinion to the Risk Control Practices Group for further consideration:

- Operator use of data on leaks that are not reported should be encouraged as part of their IM program
- One way to do this would be to require operators to use these data to develop measures (perhaps focusing on trends) that are not reported but are available for internal use and for review by state inspectors
- From a data collection and analysis perspective, consistent classification or grading of leaks by operators should be encouraged

Information on System Physical Characteristics

1. *What is the current source of the data?*

Annual Report for Gas Distribution Systems (PHMSA F 7100.1-1)

2. *What are the current data (fields)?*

Material of construction, mileage or number of services, diameter

3. *What metrics can be developed from the data?*

Trends in mileage and number of services using materials or applications having a higher potential for leakage or fracture (e.g., cast iron, unprotected steel)

4. *What are the limitations of conclusions that can be drawn from these metrics?*

- Some pipe material having a higher potential for leakage or deterioration are too specific to be reasonably separated out in nation-wide reporting (e.g., specific materials, manufacturers and lot numbers)
- Data on some materials is inconsistently reported by operator from year to year

5. *Can these metrics serve as a performance baseline (are certain metrics invalid using historical data)?*

Trending mileage or services of materials having a higher potential to leak or rupture would be a useful metric

6. *Can these become valid metrics by changing future data collection (scope or guidance)?*

Comments under leakage data should be addressed

Maturity of Integrity Management Processes

1. *What is the current source of the data?*

- All operators have practices that support compliance with Part 192 requirements
- While most operators implement processes and practices that go beyond Part 192 requirements (driven either by state requirements or individual needs to manage unique characteristics of their systems), it would be very difficult to develop a baseline characterization of existing processes

2. *What are the current data (fields)?*

3. *What metrics can be developed from the data?*

4. *What are the limitations of conclusions that can be drawn from these metrics?*

5. *Can these metrics serve as a performance baseline (are certain metrics invalid using historical data)?*

6. *Can these become valid metrics by changing future data collection (scope or guidance)?*

Data Group discussions have concluded that we cannot be certain of the nature of any requirements resulting from the DIMP, nor can we anticipate the degree of consistency of individual state inspection and reporting practices. Until these uncertainties are addressed, means of tracking trends from the ill-characterized baseline situation cannot be developed.

Exhibit C
Potential Role and Value of a Forward-Looking EFV Study

VI. Introduction

The Distribution Integrity Management Program Data Group evaluated how best to proceed with any needed data gathering on excess flow valves (EFVs). The results of this evaluation are described below.

Candidate Study Objectives

In considering the need for and potential value of gathering additional data on EFVs through a forward-looking study, the DIMP Data Group must first identify the problem we are trying to solve. The following are candidate purposes of such a study:

1. Clarifying the Performance of EFVs by developing and documenting experience data on their effectiveness and reliability,
2. To improve the basis for a meaningful cost-benefit analysis,
3. To support development of criteria clarifying the conditions under which an EFV would be expected to function effectively.

The need for additional data and choices for developing needed data for each of these purposes are explored below.

Clarifying EFV Effectiveness and Reliability

The recent Public Meeting on EFVs held in Washington on June 17, 2005, included presentations by several operators that supported the following general conclusions:

- Approximately 6.3 million EFVs have been sold (and presumably installed) in the US;
- Approximately 60% of operators belonging to AGA are currently installing EFV on single residential services where feasible (i.e., clean, dry gas greater than 10 psig), but virtually no operators that are APGA members are doing so;
- When installed in lines where they are feasible, EFVs operate as designed, terminating the flow of natural gas following rupture of service lines if the flowrate through the rupture exceeds that required for EFV activation;
- Experience has shown closure of EFVs under normal flow conditions occurs very infrequently (examples presented indicated false closures were on the order of 15% of closures associated with a line rupture, and that these false closures were usually caused by incorrect engineering (e.g., undersized valves) or significant unplanned load increases.

Given these results, it is clear that EFVs do represent a candidate tool for mitigating the consequences of distribution service line ruptures. The issue seems to be either the absence of clear factual information on EFV performance and reliability, or the level of emotion within the community of operators on EFV installation.

Given this situation, additional expensive data collection on EFV performance and reliability seems to have lower value than efforts to communicate available information to the community of operators not routinely installing EFVs currently. AGA and APGA have begun efforts to promote exchange of factual performance and reliability information within their membership. APGA members have both stronger negative feelings toward EFVs and have a much broader set of options for expending limited resources to promote public safety rather than installing EFVs.

Support Cost-Benefit Analysis

The John A. Volpe National Transportation Systems Center (Volpe) conducted two cost-benefit analyses of a potential requirement to mandate use of excess flow valves (EFV). The first analysis was published in December 2002. Comments were solicited via a Federal Register notice.[73] The analysis was revised as a result of comments received, and the revised analysis was published in September 2003.[74]

The initial analysis determined that the ratio of estimated present value of benefits to costs was 5.03, indicating that requiring installation of the valves would be cost beneficial.

Comments were received from industry, including the major trade associations - AGA and APGA, and individual utilities. Comments were also received from consultants, valve manufacturers, and public groups including firefighters.

The revised analysis, which attempted to address the comments received, determined that the ratio between the net present value of benefits and costs was 0.29, indicating that it would not be cost-beneficial to require installation of the valves.

Comments were received from two consultants, Hall and Associates (Jim Hall was the former chairman of NTSB) and Batten and Associates (Charles Batten was formerly Chief of the pipeline accident investigation program at NTSB). The industry trade associations, AGA and APGA, submitted comments in reply to the consultant comments.

One significant comment by Hall and Batten related to the selection of the analysis period. It appears that if the analysis period were extended it would pick up one or more major accidents that could significantly change the benefits picture. The 22 incidents

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[73] 68 FR 11177, March 7, 2003.

[74] Volpe conducted other cost-benefit analyses concerning EFVs in the 1990s, but those analyses are not addressed in this summary.

Volpe considered in its second analysis included only 3 deaths, 7 injuries, and about $3.6 million in property damage. Expanding the analysis period could significantly increase estimated benefits of EFV installation.

Analysis similar to an earlier Allegro analysis, extended over as many years as available knowledge will support, but not exceeding 10 years, could contribute significantly to developing a defensible number for benefits. Such an analysis could be facilitated by use of incident investigation reports compiled by the states in which incidents occurred.

To help provide perspective on the usefulness of expanding the earlier Allegro study or of conducting a forward-looking EFV data collection effort, John Erickson, subsequent to the meeting, evaluated the parameters involved in the cost-benefit analysis to determine which parameters have the greatest impact on the final result, and to offer opinions both on the uncertainty associated with those numbers and on the value of the two candidate studies in reducing those uncertainties. This evaluation, conducted with other members of the Data Group on August 30 & 31, concluded that additional data collection would not significantly improve the quality of the C-B analysis.

Support Development of Installation Criteria

Any operator that installs EFVs will need to evaluate the "feasibility" of the installation for new or replacement services. Development of criteria as the basis for these evaluations is necessary no matter how the EFV issue is ultimately resolved. Since many operators have been installing EFVs for years (reportedly up to 20 years), the experience of these operators could be tapped to develop feasibility criteria. The experience of EFV manufacturers could add to the experience base for developing these criteria. AGA and APGA are now working to identify a set of operators and manufacturers whose knowledge can be tapped in developing EFV feasibility criteria.

Observations and Follow-Up Actions

Based on the discussions described above it appears that there is limited value associated with carrying out a forward-looking EFV study. Given the nature of the data that would need to be gathered in such a study, including a minimum set of data from each leak repaired, the cost of such a study would be very high. Therefore, the subgroup noted above concluded that the following set of actions would be of greatest value.

- AGA will continue its effort to promote exchange of factual performance and reliability information among its membership.
- APGA will continue efforts to communicate real world experience with EFVs among its members.
- PHMSA and AGA/APGA will consider carrying out an expanded analysis like that previously done by Allegro. Such an analysis could contribute significantly to developing a defensible number for benefits. The first step will be to identify

the needed information and questions that would need to be posed to get that information. Information sources would include state and operator incident files.

- AGA will identify a set of operators and manufacturers whose knowledge can be tapped for development of EFV feasibility criteria, and determine how best to develop these criteria. The criteria will need to consider at a minimum the following: line pressure, expected future changes in line pressure, the presence of liquids in the line, the presence of solid particles in the line, environmental conditions that could reduce EFV functionality. Among the operators to be considered are East Ohio Gas, Bay State Gas, UGI and Brooklyn Union.

Exhibit D
Summary of Existing Information on EFV Use and Performance

Introduction

Numerous studies have been conducted during the past year to help clarify what is actually known about EFV installation and performance experience. These studies have been commissioned either by PHMSA or by NAPSR. The surveys summarized here include:

1. "Survey Responses of State Public Utility Commissions on Excess Flow Valve", Ken Costello - Senior Institute Economist, The National Regulatory Research Institute at The Ohio State University, June 1, 2005.
2. "PHMSA/NAPSR Survey of State Experience with EFV Performance - Summary of Responses", Anne Marie Joseph, PHMSA, May 25, 2005.
3. "Excess Flow Valve Survey Summary", C. B. Oland, Oak Ridge National Laboratory, September 1, 2005.
4. "Evaluation of Excess Flow Valves in Gas Distribution Systems", Mona C. Mc Mahon, General Physics Corporation, August, 2005.
5. "Summary of Survey on Excess Flow Valve Experience", Rex Evans, Illinois Commerce Commission, DIMP Data Group, September, 2005.

The scope of these surveys is summarized below.

	NRRI Survey	**PHMSA-NAPSR Survey**	**PHMSA-ORNL Survey**	**General Physics Study**	**DIMP Data Group**
Purpose of Study	Determine State Requirements and Future Intentions	Assemble State Experience	Assemble Experience from Selected Operators	Evaluate Standards & Limited International Experience	Assemble Experience from Experienced Operators
Nature of Report	Formal Report	Matrix of Results	Formal Report	Formal Report	Matrix of Results
Data Source	State Public Utility Commissioners	State Pipeline Safety Representatives	Representatives of Operators	Open Literature	Representatives of Operators
Number of Respondents	50	50	9	N/A	10 of 12 contacted

An additional important source of information on EFVs, and on the perspective different stakeholder groups have on their value was the Public Meeting held on June 17, 2005. Highlights of that meeting are included as an Addendum to this document.

Summary of Observations and Conclusions

The results from these surveys are summarized in Table 1. The primary observations and conclusions that can be drawn from these results are summarized below.

Observations

1. All operators currently seem to be complying with the requirement to notify owners of new or replacement service about the opportunity to install an EFV.
2. Operators focusing on compliance with notification requirements typically pass the cost of installation to the owners.
3. Based on PHMSA survey and NRRI draft survey of current usage
    a. States do not collect data on performance (incidents prevented or false closure)
    b. The rate of false closures appears to be low (from limited information)
    c. No State currently requires installation or is considering such a requirement
    d. In 16 States, mostly Eastern, all or large percentage of operators install EFVs voluntarily
    e. In 9 states, mostly Western, no operators install EFVs voluntarily
    f. Larger operators seem more likely to install EFVs voluntarily
    g. Small percentage (between 0.2 and 2 percent) of notifications result in valves being installed - no clear evidence exists to explain this low election rate by developers and home owners
4. PHMSA-funded review of incidents by Allegro to determine potential EFV effectiveness has shown
    a. There were 634 incidents reported on distribution systems from 1999 - 2003
    b. Review of incident reports identified 101 (16 percent) in which an EFV could potentially have reduced or eliminated consequences
    c. This is an upper-bound estimate (limitations of data prevent further drill down)
    d. Most (85%) of 101 candidate incidents were caused by:
        i. Excavation damage - 47%
        ii. Vehicle damage - 38%
5. Based on discussion at the June Public Meeting (Addencum D-1) the following was observed
    a. <u>Areas of agreement</u>
        i. EFVs will not operate under all conditions (up to 60% of new services in Connecticut will not support EFV use)
        ii. Excess flow valves (EFVs) should not be mandated for all services - they should only be used when operating conditions support their use, and only on new or replacement single family residential services
    b. <u>Areas of disagreement</u>

i. Excess Flow valves should be considered as one tool in managing the integrity of distribution pipeline systems *versus* EFVs should be mandated for all new and replacement services where they are technically feasible

ii. The overall cost of installing EFVs on new and replacement single family residential services is favorable relative to that of complying with current notification requirements (including litigation risk) *versus* installing EFVs on all new or replacement single family residential services is more costly than complying with current notification requirements

6. Anecdotal evidence exists that the presence of an EFV that functions as designed to cut off gas supply following excavation damage occasionally leads to non-reporting of the damage by the excavators. Whether adverse safety or economic consequences have resulted from instances where damage has not be reported is not clear.

Conclusions

1. EFVs are not designed to operate under all conditions, therefore, there is a need for clear guidance describing conditions under which EFVs would (or would not) be expected to function as designed
2. The preponderance of information supports the conclusion that, when properly specified and installed, EFVs function as designed
3. Different operators have reached different conclusions on whether the overall cost of installing EFVs on new and replacement services is favorable or unfavorable relative to that of complying with current notification requirements; operator conclusions seem to reflect their assumptions (e.g., whether or not they include litigation risk, how they treat cost recovery)
4. There is limited value associated with carrying out an expansive forward-looking EFV data collection effort. The Data Group concludes that the following represents a more effective course of action:
   a. AGA continuing with its effort to promote exchange of factual performance and reliability information among its membership,
   b. APGA continuing efforts to communicate real world experience with EFVs among its members,
   c. PHMSA and AGA developing EFV feasibility criteria, considering at a minimum the following: line pressure, expected future changes in line pressure, the presence of liquids in the line, the presence of solid particles in the line, environmental conditions that could reduce EFV functionality, and the length of line from main to meter.
5. Consider changing the incident reporting forms to include the operator's assessment of whether an EFV, if present, would have mitigated the incident will improve the quality of evidence on the impact of EFVs on distribution safety. (The Coordinating Group decided that this additional reporting would be of little value.)

Table 1 Summary of EFV Survey Results

Question/Issue	NRRI	PHMSA/NAPSR	ORNL	General Physics	DIMP Data Group
Percent of operators voluntarily installing EFVs	• Five states & DC: all - primarily in East • Ten states: none - primarily in West • Three states: no data • <25% operators over 29 states + DC • 23% of "total" (699) operators install; total appears low	• 2/3 of states have at least one operator who voluntarily installs • 14 states with ≥90% of LDCs voluntarily installing • 25 states with ≤5% of LDCs voluntarily installing	• 5 of 9 surveyed (55%) install voluntarily • One of the operators responding "no" (Nicor) has since changed its policy and began installing EFVs voluntarily on 7/1/05		• 8 of 10 surveyed (80 %) acknowledge installing voluntarily • Others either did not exist prior to the regulation or their response was unclear
Following notification, percent of customers purchasing EFV	2% (data from 7 states)	Most do not purchase	0.2% (based on total EFVs installed for 4 companies not voluntarily installing)		Not Applicable
Trends in installations	Volunteers tend to be larger, private operators		No trend apparent. Both private and municipal operators report both voluntary install and customer choice.	Germany: mandated since 2003 France: mandated for new PE since 2000 Japan: EFV integral with customer meters - this reflects a different approach to that in the US	
Total number installed	approx 1.2 million reported		414,142		
Cost recovery	rate base - most private operators customer charge - OH, even if voluntary install		5 of 9 companies pass costs on to homeowner in some way		Operators accept cost

Question/Issue	NRRI	PHMSA/NAPSR	ORNL	General Physics	DIMP Data Group
Incremental installation cost (per service)			$6 to 50 if voluntary; $20 to 120 if notify		$8 to $60
Maintain/replace cost			$500-$2000		Replace~$900 Reset ~$28 - $400
Range of line pressures	Mostly 10 psig; IA=20		10 – 300 psig		Minimum 10 psig
How do service personnel know EFV is installed?			Service records, metal tags on service riser		Service records, metal tags on service riser
Number of third party damage incidents averted			no data		No data
Investigation after EFV actuation?			Generally not unless valve must be dug up		Cause of actuation determined
Manufacturer experience	Limited info		Good, limited range		Good
Number of normal activations			No data		Variable data
Number of spurious activations			93 reported, little data		No data
Reliability experience			Very low occurrence of trips from undersize; all surveyed agree EFVs are reliable - most common cause of inoperability is debris -lack of data on long-term reliability	Very low occurrence of trips from undersize; all surveyed agree EFVs are reliable - most common cause of inoperability is debris -lack of data on long-term reliability	Highly reliable – good experience except when liquid or particles in gas
Responsibility for restoration cost			Customer (question applicable to customer-purchased EFVs only)		Operator

Question/Issue	NRRI	PHMSA/NAPSR	ORNL	General Physics	DIMP Data Group
State policy on installation	None require. Eleven "encourage"	None mandate. DC & NJ report formal policies. Nine have concerns with false closures.			
Install data available?	- No: 38 States - Yes: 12 States		# installed, yes # actuations, no		Partial
Conditions under which EFV not installed	- Low pressure: 12 states - Pressure or contaminants: 17 states - some other				• Pressure too low (<10 psig) • Prior experience with contaminants in gas stream • Interference with O&M activities (e.g., blowing liquids from service line) • Service line feeds multiple residences
Minimum line pressure EFV considered effective	Generally 10 psig		10 psig is lowest reported install pressure		10 psig
Operational data available?	Generally not available. Limited data implies false closure rate <0.04%, perhaps much less		No. Reported data on false closures implies: 0.04% (2 companies); 0.02% (all companies)[75]		Limited

[75] The questions on inadvertent failures were apparently confusing. Two companies (PG&E and Consumers Energy) reported more than a trivial amount of inadvertent operations. The 0.04% rate is calculated using the values reported by these companies for # failures and # EFVs installed. Rate is not annual, but is

Question/Issue	NRRI	PHMSA/NAPSR	ORNL	General Physics	DIMP Data Group
Who should be responsible for deciding on EFV?	Customer: 13 states Operator: 16 states States: 3 states Feds: 6 states Shared: remainder				Operator

rather % of EFVs installed that have ever failed. (Note that Consumers reports that its failure rate is lower than when it began installing due to better understanding of how to estimate load). Three companies did not report or indicated they had no data. Four companies reported zero or single-digit number of failures, even though in one case the company has 132,000 EFVs installed. No data reports are treated as zero in calculating the 0.02% failure rate. This number is quite suspect, but the range of # failures seems between 0.02% and 0.04% with considerable certainty.

Addendum D-1
Highlights of Public Meeting on EFVs
June 17, 2005

Summary Areas of General Agreement

- Safety is a top priority for gas distribution operators
- EFVs will not operate under all conditions (up to 60% of new services in Connecticut will not support EFV use)
- Excess flow valves (EFVs) should not be mandated for all services - they should only be used when operating conditions support their use, and only on new or replacement services
- Current data on the effectiveness of EFVs is limited, and data gathering should be aggressively pursued
- Operators respond to significantly more leak calls than do fire fighters, so they are at least as interested in protecting first responders
- 6.3 million EFVs have been sold in the US

Summary Areas of Disagreement

- Excess Flow valves should be considered as one tool in managing the integrity of distribution pipeline systems *versus* EFVs should be mandated for all new and replacement services in which they are feasible
- The overall cost of installing EFVs on new and replacement services is favorable relative to that of complying with current notification requirements (including litigation risk) *versus* installing EFVs on all new or replacement services is more costly than complying with current notification requirements
- Operators should decide how best to use resources to address distribution safety considering both prevention strategies and mitigation strategies *versus* individual safety devices like EFVs should be mandated by regulators if they work

Operator Case Studies

- Consumers Energy has determined that the net present value favors installing EFVs on new and replacement services
- Five of the nine operators in the survey conducted by PHMSA through ORNL believe installation of EFVs is less costly than notification
- Consumers Energy, which has about 1.7 million services, has installed 146,000 EFVs in six years

- Neither Southwest Gas nor the City of Mesa routinely installs EFVs; Philadelphia Gas Works has a policy of installing EFVs where feasible, but only installs 90 to 100 per year where pressure conditions are met
- Notification is typically provided to developers not eventual owners of residences

EFV Studies

- NRRI study found no states where EFVs are mandated
- NRRI study identified one state (Ohio) where 450,000 EFV are reportedly installed, and identified several states where the vast majority of operators have a policy of installing EFVs on new and replacement services
- One state reported 100 closures per year of which 15 were false closures; another reported 40 actuations of which 6 or 8 were spurious (resulting from incorrect engineering or added load)

NTSB (Past and Present) Perspective

- NTSB believes that it's time to mandate EFVs
- Notification was intended to be to owners, not developers
- AGA and APGA committed five years ago to gather EFV performance data and have not begun, leading to the current unavailability of data
- There are no standards for notification of customers, so operators can actively discourage EFV installation (e.g., by emphasizing the customer responsibility for costs related to resetting, maintenance or replacement of EFVs)
- Some operators have up to twenty years of experience with EFVs; they should be surveyed regarding performance (e.g., East Ohio Gas, Bay State Gas)
- Jim Hall noted that EFVs will also reduce emissions of methane - a greenhouse gas

Fire Services Panel

- Noting that over 100 firefighters are killed per year in the line of duty, Congressman Weldon expressed support for EFVs as one inexpensive way to save property and lives
- Representatives of the fire service were unanimous in supporting mandatory installation of EFVs
- Ted Lemoff described the inherent limitations of EFVs, including their inability to mitigate leaks or ruptures of lines downstream of the gas regulator
- George Miller expressed support for mandating EFVs as well as strengthening damage prevention efforts and enforcement, and implementing comprehensive integrity management programs

State Commissioners

- Don Mason expressed concern about whether decreases in main line pressure as new services are added downstream of EFV installations will impact EFV viability
- Commissioners noted that new costs must be justified, and that the benefits must be weighed against the costs
- Director Tate expressed the philosophy that the best decisions are those made locally with full knowledge of the local conditions, and the benefits and costs
- Commissioners generally expressed support for decisions on the use EFVs being made by operators in the context of integrity management programs
- Director Tate noted that Fire Marshals in Tennessee want more training as their first priority

AGA/APGA

- AGA will continue to conduct exchanges of technical and performance information among member companies to support their informed, risk-based decisions on when to install EFVs, beginning with a workshop in August
- EFVs are one tool that may be cost effective in certain situations
- Public gas companies are different in that they must compete with other city agencies for resources dedicated to improving public safety
- Both AGA and APGA are opposed to a mandate to install EFVs

State Pipeline Safety Representatives

- Data on situations in which EFVs may have mitigated events may be available from state regulatory agencies that investigate incidents
- Operators need to present a case for why they do not install EFVs
- One condition that may invalidate EFV application is contaminants in lines
- Mary McDaniel expressed support for separating EFVs from the integrity management effort
- All agreed that additional data on EFV performance is needed

Exhibit E
Additional Information on Excess Flow Valve Performance
Distribution Integrity Management Program Data Group Survey

Introduction

During the spring 2005 PHMSA commissioned a survey of nine operators to better understand their experience with EFVs. This study was carried out by Oak Ridge National Laboratory (ORNL). During the Public Meeting in June 2005 questions were raised about the process by which the nine operators were chosen. In an effort to expand the data base of EFV operating experience, the Data Group from the Distribution Integrity Management Program (DIMP) surveyed several operators including those suggested by Charles Batten (formerly with the NTSB) that reportedly have been installing EFVs for longer than twenty years. Ten of the 12 operators contacted responded to the survey. Four of these ten were from the list of highly experienced operators. The four respondents from this list were KeySpan Energy, Elizabethtown Gas, Bay State Gas, and UGI Utilities.

The survey was conducted by Rex Evans of the Illinois Commerce Commission, with assistance from AGA to identify individual contacts at the operators being surveyed. The instrument used in the survey was the same as that used previously by ORNL, except that questions were added to seek information on experience in which excavators struck lines containing EFVs, ruptured the line, and left the scene without reporting the hit. These additional questions were intended to seek out further anecdotal information on both whether such “hit and run” behavior is prevalent and what safety or economic consequences have resulted. Anecdotal evidence existed prior to the survey indicating cases of expanded economic damage following a hit with EFV closure and no report when the dwelling was a seasonal residence, the owner was on an extended absence, or gas appliances were not in use at the time of the damage. This instrument appears as Addendum E-1.

Participating Operators

The operators that responded to the survey together with the individuals who supplied the requested information are shown in the table below.

Company	Person Supplying Data	Title
KeySpan Energy	Arthur Shapiro	Manager, Regulatory Compliance
Elizabethtown Gas Company (NJ)	Phil Salvatore	Compliance Engineer
Bay State Gas Company - A NiSource Company	Edward Collins	Project Engineer
UGI Utilities, Inc.	James R Heintz	Manager, Systems Integrity and Operations
Peoples Gas Corporation (Peoples Gas Light & Coke Co.)	Alfredo S Ulanday	Manager, TTS & Compliance

Colorado Springs Utilities	Mason Parsaye	Manager, Standards
CoServ Gas LTD	Brian Stiles	Operations & Maintenance Manager
Peoples Energy Corporation (North Shore Gas Company)	Alfredo S Ulanday	Manager, TTS & Compliance
Ameren IP	Jerome Themig	Manager, Gas Compliance & Training
CPS Energy	Darren Lange	Director, Gas Operations & Construction

Summary of Results

The reported number of services and installed EFVs are shown in the table below, along with comments by the operators on their experience with excavation damage in which the offending excavator failed to report the hit.

Company	Number of Services	Number of EFVs Installed	Experience with "Hit & Run"
KeySpan Energy	~750,000	~200,000	• If EFV trips it will be noticed • Some experience with this practice in aggressive excavators • Addressed through aggressive enforcement practices
Elizabethtown Gas Company (NJ)	196,000	56,586	Not known
Bay State Gas Company - A NiSource Company	3.16 million	375,000	This is 1 of 4 operational issues cited
UGI Utilities, Inc.	~300,000	125,491	Some situations exist
Peoples Gas Corporation (Peoples Gas Light & Coke Co.)	503,614	77.179	• Some occurrences, not tracked • No safety consequences or additional economic consequences noted
Colorado Springs Utilities	169,044	2,748	Some experience; problem typically identified by customer
CoServ Gas LTD	45,000 (?)	45,000	• 35% of excavator-caused actuations are not reported • Occurs when service is vacant
Peoples Energy Corporation (North Shore Gas Company)	140,115	~39,000	• Some occurrences, not tracked • No safety consequences or additional economic consequences noted
Ameren IP	400,594	≥70,000	• Few isolated instances
CPS Energy	301,893	39,177	

As shown in the above table, all operators responding to the question on "hit and run" excavation damage in lines with EFVs indicated that the phenomenon occurs; however, EFV closures are typically reported by the home owner as lost gas supply (if they are home) and no safety or economic consequences beyond those associated with repairing the damaged line have been identified. Other findings from the survey are consistent with those reported by ORNL in the earlier survey, and are shown below. The lone area in which operators in the current survey differ from those in the earlier ORNL survey was in their installation of EFVs prior to the regulation requiring notification for new and replacement services.

EFV Operating Experience

Operators reported the following EFV operating experience:
- No significant problems with reliability have been experienced
- Actuations and false trips typically not specifically tracked
- Reported installation costs range from $8 to $60, while reported replacement costs were ~$900, and costs to reset an EFV following a trip were reported to be between $28 and $400.

Drivers for Installing EFVs

Operators reported the following reasons for their decision to install EFVs:
- Enhance public safety
- Difficulty and cost in administering customer notification and documentation
- Minimizing escaping gas prior to the arrival of a repair crew
- Choice of installing EFVs in lieu of a curb valve

Operational Issues Reported

Operators reported the following operational issues, none of which led to change in their decision to install EFVs:
- False actuation resulting from contaminants in line (e.g., liquids, plastic shavings, dirt)
- Customer installation of additional gas equipment without notifying the gas company
- Small capacity EFVs less tolerant of added load
- Excavation damage not reported because gas not blowing following EFV closure

Situations when EFVs aren't installed

Operators reported the following situations in which EFV are not installed:
- Insufficiently high pressure (<10 psig)
- Prior experience with contaminants in gas stream
- Interference with O&M activities (e.g., blowing liquids from service line)
- Service line feeds multiple residences

Addendum E-1
Survey Form

To understand excess flow valves (EFV) performance, reliability, and installation practices more thoroughly, the Distribution Integrity Management Program Data Group is conducting an exercise that will expand our knowledge on EFV use. Case studies will be developed by asking several gas distribution companies a series of questions on their EFV experience.

To breed consistency, ensure repeatability, compare experiences, and draw valid conclusions of one approach versus another, the Data Group will use the series of questions below for this survey.

Operator Data **(This data is for internal tracking use ONLY and will not be published)**	
Company Name :	
Mailing Address :	
Contact Name :	
Contact Title :	
Phone Number :	
Fax :	
Email :	
Service Area :	
Number of Services:	

1. Were you installing EFVs before the regulation? If you did, why did you install it versus keeping records?

2. How many services currently have EFV's?

3. Is EFV installation voluntary or required by company policy? Can you comment on the policy drivers? Is installation part of a standard?

4. For voluntary installations, how many homeowners have requested EFV installation on–

    a. Existing services? ___________

    b. New services? ___________

5. Is any part of the cost charged to the homeowner?

6. What is the incremental average cost to install an EFV?

7. Which manufacturers' EFVs do you usually install?

    Is there a particular model ___________________________________

    Is there a particular size? ______________________________________

8. What is the range of operating pressures on services that you install EFVs on?

9. How do you alert service personnel that a service has an EFV?

10. Do you know how many third-party damage incidents per year there were on your entire distribution system? Similarly, do you know how many third-part damage incidents were there on service lines with EFVs?

11. What kind of investigation is performed by the company after an EFV is activated?

12. For companies using EFVs from different manufacturers, has there been a pattern of failure that companies have noticed?

How many EFV actuations have been experienced due to gas line leaks or failures?

Before the meter. ________________

After the meter __________________

Leading to excavation damage of which the operator was not notified by the excavator_______________________________________

13a. Were there safety or economic consequences for actuations caused by excavation damage in which the operator was not notified? How pervasive have instances of damage accompanied by failure to notify been? - Quantify or describe consequences.

13. How many inadvertent EFV actuations have been experienced

Due to excess demand ________________

Due to EFV failure ___________________

Due to contaminants getting trapped in the EFV __________________

Total ___________________

14. What would you say your experience has been with the reliability on EFVs? Elaborate on your experience?

15. What is the average restoration cost of inadvertent EFV actuations? Is the homeowner or company responsible for any damages?

$______________________

16. On voluntary installations, who pays for the restoration in the event the EFV trips?

17. For your system with EFVs, do you have data showing, on average, how many accidents/year occurred before your EFV installation standard was enacted?

18. Do you have data on how many times an EFV was actuated on a service with an EFV?

19. Can you comment on what particular EFVs you have had the most success with?