U.S Department of Transportation

Pipeline and Hazardous Materials Safety Administration (PHMSA)

Distribution Integrity Management Program (DIMP) History

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Integrity Management – A New Approach to Improving Pipeline Safety

Pipelines have a commendable safety record and are the safest way of transporting hazardous materials in the U.S. Still, incidents continue to occur, though infrequently, and some result in significant consequences. PHMSA adopted integrity management regulations for transmission pipeline, beginning in 2000, to reduce the frequency of these incidents and improve safety. Under the new regulations, operators of hazardous liquid and gas transmission pipelines were required to analyze their pipeline systems to identify threats to pipeline integrity and rank by risk their relative importance. Operators are then required to take actions to address these threats. Operators must identify those segments of their pipeline where an accident could result in significant consequences, prioritize these segments, assess them periodically, repair identified anomalous conditions that meet specified criteria, and evaluate the results to validate that their programs assure the integrity of their pipelines. Integrity management requires operators to use a risk-based approach to manage the safety of their pipelines.

PHMSA published integrity management regulations for hazardous liquid pipelines in 2000 (49 CFR §§195.450 and 195.452) and followed them with requirements for natural gas transmission pipelines in 2003 (49 CFR Part 192 Subpart O). PHMSA's web site for integrity management (http://www.phmsa.dot.gov/pipeline/imp) contains additional background information about integrity management.

Significant incidents (those involving fatalities, injuries requiring hospitalization, or property damage exceeding reporting thresholds) occur on distribution pipeline systems at an annual rate consistent with those on other pipelines. Serious incidents (those involving fatalities or injuries) occur much more frequently on distribution pipelines. During the period 1991 through 2010, six times more serious incidents occurred on gas distribution pipelines than occurred on gas transmission pipelines. Distribution pipelines experienced nearly nine times more serious incidents than hazardous liquid pipelines during this same period.[1] (Detailed information on the occurrence of pipeline incidents can be found on PHMSA's Pipeline Stakeholder website, http://primis.phmsa.dot.gov/comm/). These data make clear that a significant reduction in the rate of pipeline incidents resulting in serious consequences could not be achieved without addressing gas distribution pipelines. It was necessary to determine how to apply integrity management principles to gas distribution pipelines.

The American Gas Foundation (AGF) Study

The gas distribution pipeline industry took the lead in addressing this question. AGF sponsored a study in 2004 to provide independent technical insight into natural gas distribution system safety performance and the issues that affect it. The study involved:

[1] The higher rate of incidence on gas distribution pipelines results largely from the fact that there are many more miles of such pipelines. The rate of serious incidents per mile is similar to that for gas transmission pipelines.

- A detailed analysis of the natural gas distribution industry's safety performance;
- An overview of current regulations and industry practices that address threats to the natural gas distribution infrastructure;
- A description of the characteristics that differentiate natural gas transmission pipelines from distribution pipelines; and
- Identification of industry and government initiatives that were already in place to assure continual improvement in regulation and practices affecting distribution integrity.

The AGF study was overseen by the Distribution Infrastructure Government-Industry Team (DIGIT), which included members from the Foundation, the American Public Gas Association (APGA), the National Association of Pipeline Safety Representatives (NAPSR), the National Association of Regulatory Utility Commissioners (NARUC) and PHMSA (the Research and Special Projects Administration – RSPA – at the time). The study was published in January, 2005.

The safety performance review involved a detailed statistical analysis of distribution incidents in the U.S. Department of Transportation (DOT), Office of Pipeline Safety (OPS) database over the period of 1990 through 2002 (the latest time period for which meaningful data was available at the time of the study). The main findings of this study were:

- Of the 1,579 incidents for gas distribution during this period, 601 were "serious incidents" - those involving a fatality or an injury requiring hospitalization.
- There was a statistically determined downward trend in the incidence of serious incidents from 1990 through 2002. The number of such incidents each year decreased by approximately 40% over the period studied.
- Outside force damage to the infrastructure was the major cause (47%) of serious incidents during the study period.
- The predominant component of outside force damage was third party damage, (typically excavation damage inflicted on distribution facilities by a third party not related to the gas system operator or its surrogate), contributing nearly 35% to the total number of serious incidents.
- Corrosion, construction/operating error, and incidents accidentally caused by the operator each accounted for less than 10% of the serious incidents.
- 46% of serious incidents occurred on distribution mains, and 34% occurred on service lines and meter sets (combined). (Data for the remaining 20% did not include information from which to determine the portion of the pipeline system in which they occurred).
- Normalized per 100,000 miles over the study period, the average fatality and injury counts for gas distribution pipelines were essentially the same as the counts for gas transmission prior to the implementation of integrity management for transmission pipelines.

AGF conducted a survey of 23 gas utility operators representing a cross-section of the industry about industry practices intended to address the causes of distribution infrastructure incidents. The study also examined if gaps existed between industry practices and government regulations in addressing incident causes. Additionally, the study included a review of some of the important differences between natural gas transmission pipelines and distribution systems in order to better understand why there might be differences in safety performance. Finally, the study sought to identify gaps in data, regulations, or practices that need to be closed in order to enhance distribution infrastructure safety.

The results of the survey indicated that operators address threats to distribution system integrity through compliance with pipeline safety regulations and various industry practices. The survey's main findings were:

- There were no apparent gaps between specific threats to distribution integrity and pipeline safety regulations or industry practices that address the threats. (The effectiveness of the regulations in addressing threats was not covered in the survey nor were government regulators surveyed).
- The five processes having the highest impact on distribution integrity are (1) cathodic protection systems, (2) leak surveys, (3) operator qualification programs, (4) one-call systems, and (5) planned pipe replacement programs.
- Operators use prevention and mitigation measures that exceed the requirements of the federal pipeline safety code to address specific threats to the integrity of distribution pipelines.
- Operators address the dominant threat of third party damage through prevention and mitigation measures that include those required to meet pipeline safety regulations and additional measures that exceed the pipeline safety code requirements.
- Over 80% of the respondents reported employing risk-ranking tools to evaluate their distribution infrastructure, often in conjunction with pipe replacement and/or infrastructure management programs, and in allocating resources for additional prevention and mitigation measures to address a particular threat.
- Over 65% of the responding companies had planned replacement programs for cast iron pipe and almost 80% had such programs for bare steel pipe. The survey also ascertained that most operators do not have fixed timeframes for such replacements.
- Pipe replacement between 1990 and 2002 reduced the amount of cast iron main mileage by 21% and the amount of bare, unprotected steel main mileage by 7%. During the same period the number of bare, unprotected steel services was reduced by 13%.

DOT Re-assessment of Reported Incidents

Reducing the number of consequential incidents requires an understanding of their causes. PHMSA has long required that pipeline operators report incidents that result in certain consequences. Among these reported incidents are all incidents that result in a death or an injury requiring hospitalization. Incidents that result in property damage exceeding a specified threshold also have been required to be reported. That threshold is currently $50,000.

Concurrently with the AGF work, PHMSA determined that its incident data required improvement in order to support a better understanding of incident causes. The incident report form used prior to early 2004 classified the cause of an incident into five categories:

- Accidentally Caused by Operator
- Construction Defect or Operation Error
- Corrosion
- Damage by Outside Force
- Other

These broad categories made it difficult to identify the real hazards. PHMSA revised the form in 2004 to account for seven broad categories and 25 sub-categories of incident cause. This would facilitate more thorough analyses of the causes of future incidents. The historical record, however, was reported under the five broader causes and could not be included in these analyses.

PHMSA contracted with Allegro Energy Consulting to re-classify distribution pipeline incidents that had been reported from 1999 to 2003, the five years preceding revision of the incident report form. In addition to the reported "cause," each incident report included a narrative summary of the event. Allegro reviewed those narratives, and other information included in the reports, to re-classify them into the new, more-detailed cause categories. Allegro's work confirmed that consideration of the reported causes, alone, did not provide a useful understanding of the hazards that result in distribution pipeline incidents. This work was published in a report entitled *Safety Incidents on Natural Gas Distribution Systems: Understanding the Hazards* in April 2005.

For instance, the category "Damage by Outside Force" accounted for 61% of the 634 incidents that occurred from 1999 to 2003 on distribution pipelines. This category lumped together incidents caused by Excavation and Mechanical Damage, those caused by Natural Forces, and those caused "Other Outside Force" such as vehicles and fires. These causes involve different hazards, and would require different management strategies. In addition, a full 25% of the incident causes were reported in the category "Other," providing no information on which to base approaches to reduce their frequency.

The use of the five broad categories also masked the specific cause of "serious incidents," those that involve an injury or fatality. Over 1999 to 2003, 37 out of 40 of the incidents that resulted in a fatality – more than 90% – and 73% of the incidents that resulted in an injury were the categorized as either Damage by Outside Force or Other. The former category was often treated as a surrogate for so-called "Third Party Damage" or excavator damage. Initiatives aimed at reducing excavator damage would thus appear to target these incidents. In reality, the category of Damage by Outside Force included the damage from Vehicles, and Fire/Explosion as the Primary Cause, both of which would not be addressed actions directed at reducing excavator damage.

Allegro's work re-classified 385 incidents in the old cause category of Damage by Outside Forces into the new categories of Natural Forces (32 incidents), Excavation and Mechanical Damage (208 incidents), Other Outside Forces (135 incidents), and Miscellaneous/Unknown (7 incidents). Reclassification of the old cause category of Other, which accounted for 25% of the incidents, resulted in a reduction of more than half in this category. In all, Allegro reclassified 103 incidents from the old

Other category, providing information on the causes and hazards that was previously not available. Allegro was unable to reclassify 12% of the incidents, which remained in the Miscellaneous/Other category.

Analysis of the re-classified incidents reinforced that multiple approaches were needed to reduce the frequency of incident occurrence. Excavation and Mechanical Damage accounted for 243 of the 634 incidents from 1999-2003 or 38%. Of these incidents, 91% were caused by third-party activities, and 9% were caused by the operators' or their contractors' actions (1st and 2nd parties). This category is largely comprised of traditional excavation and mechanical damage – digging, excavation, drilling, boring. Examples include: construction activities such as trenching, or earth moving; utility installation such as cable, telephone, or water lines. These are all the activities that would normally be covered by One-Call statutes. The prevalence of these incidents demonstrated that One-Call programs could be improved. Some incidents resulted from failure of the would-be excavator to make the call or wait the appropriate time before undertaking the project. In addition, some categories of excavators (e.g., municipalities) were excluded from One-Call requirements in some states.

Vehicle-related incidents accounted for 67 of the 634 incidents or 11%. These incidents typically involved an automobile crash and a fire. Some involved driving while intoxicated, and some a rollaway vehicle, a riding lawnmower, or snowplow. One even involved a railroad. In the majority of cases, the Meter Set Assembly was damaged (44 or 66%).

Excavation and mechanical damage and damage by vehicle previously had both been reported under the category "Damage by Outside Force." These causes obviously require different mitigation strategies. Allegro's work reinforced that the fundamental premise of integrity management applied to distribution pipelines as well as to gas transmission and hazardous liquid pipelines – that operators needed to understand the hazards applicable to their pipelines and take appropriate actions to manage their risks.

Congressional Interest and Direction

The DOT Inspector General (IG) had also concluded that integrity management should apply to distribution pipelines, in a report also issued in 2004. The IG testified before the United States House of Representatives Committee on Transportation and Infrastructure Subcommittee on Highways, Transit and Pipelines on June 16, 2004 and the Committee on Energy and Commerce Subcommittee on Energy and Air Quality on July 20, 2004. In both cases, he referred to the need for integrity management programs (IMP) for distribution pipelines by stating, "The IMP is a risk-management tool designed to improve safety, environmental protection, and reliability of pipeline operations. That natural gas distribution pipelines cannot be internally inspected using smart pigs is not by itself a sufficient reason for not requiring operators of natural gas distribution pipelines to have IMPs. Other elements of the IMP can be readily applied to this segment of the industry, including but not limited to (1) a process for continual integrity assessment and evaluation, and (2) repair criteria to address issues identified by the integrity assessment and data analysis."

Subsequently, the FY 2005 Conference Committee on Appropriations directed[2] PHMSA to:

> *Natural Gas Distribution Pipeline Safety*- In lieu of directives proposed by the Senate, the conferees direct the Office of Pipeline Safety 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. This report should detail the IMP implementation approach for operators of natural gas distribution pipelines, including development of guidance for adoption by states, and publication and promotion of best practices and development of national consensus standards and/or federal or state regulation. In addition, the report should include specific milestones and performance measures on the actions that will be necessary to carry out the IMP initiative and should examine the financial implications of an IMP and impacts on natural gas consumers. The Administrator shall provide quarterly updates to the House and Senate Committees on Appropriations regarding the status of the implementation.

PHMSA submitted its report to Congress on June 20, 2005. PHMSA described the principal focus of the then-existing integrity management regulations for gas transmission and hazardous liquid pipelines as to identify the portions of each pipeline system that pose the most risk; to inspect the physical condition of those portions of the pipelines; and to repair any defects that could challenge the pipeline integrity. PHMSA noted the fundamental principles of integrity management require: understanding the infrastructure and the risks it poses, and then taking actions to address those risks. PHMSA's report stated:

> "There are significant differences in the design of gas distribution pipeline systems compared to the pipelines subject to current integrity management regulations. These include pipe size, operating pressure, materials, and the large number of branches and connections in distribution systems. These design differences significantly limit the applicability of the inspection techniques currently in use for those pipelines to distribution pipeline systems. The challenge is to develop appropriate methods to apply the principles of integrity management to enhance the safety of distribution pipeline systems, while remaining mindful of costs and service disruptions and their potential impact on consumers."

[2] House of Representatives Report 108-792, November 20, 2004.

PHMSA reported that it had implemented a program jointly with its state partners and a broad range of stakeholders to identify means appropriate to distribution pipelines to focus attention on areas that pose the highest risk and to better assure the integrity of those portions of the distribution systems, in other words, integrity management. The first phase of the program was to be completed in 2005 and would identify the nature of requirements that might be imposed and any additional guidance or consensus standards that might be needed to assist operators in implementing any integrity management requirements. This phase would include consideration of a multi-faceted set of potential approaches, including regulations and guidance, but would also consider a national education program, development of new inspection technologies, and legislative models that states could adopt. The second phase, to begin in January 2006, would include development of appropriate requirements by OPS and preparation of guidance/standards by appropriate bodies.

DIMP Phase 1 Report - Integrity Management for Distribution Pipelines (2005)

Four multi-stakeholder work/study groups were established under the oversight of an Executive Steering Committee including representatives from PHMSA, industry, state regulators, state Fire Marshalls, and the public. The work/study groups held a series of meetings, separately and together, over a period of months to collect and analyze available information and to reach findings and conclusions to inform future work by PHMSA. The groups 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 work/study groups considered, and discussed with the Executive Steering Committee, several options for implementing integrity management principles for distribution pipelines:

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

The groups concluded that the most useful option for implementing distribution integrity management requirements was a combination of some of these: 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.

This conclusion was based on a number of factors. Differences between gas distribution pipeline systems and gas transmission pipelines make it impractical simply to apply the integrity management requirements for transmission pipelines to distribution. The significant diversity among gas distribution pipeline operators and their pipeline systems 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:

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.

These elements are similar to the programmatic aspects of integrity management requirements for gas transmission pipelines.

These elements also do not include identifying high consequence areas, on which integrity requirements for gas transmission pipelines are focused. The groups concluded that integrity management should be applicable to entire distribution pipeline systems. Thus, 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 concluded that it should be possible to develop and promulgate a regulation consistent with the work/study groups' conclusions. They also concluded that guidance would be needed to assist operators in implementing the high-level regulatory provisions in their particular circumstances. Detailed guidance would 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. The groups concluded that federal legislation was likely needed to support the development and implementation of such programs by all states. This issue was addressed in the Pipeline Improvement, Protection, Enforcement, and Safety Act (PIPES Act) of 2006, discussed below.

The groups concluded that excess flow valves (EFVs) could be a valuable incident mitigation option, but that a federal mandate for their installation would be inappropriate. (All the work/study 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. The groups concluded a regulatory provision that would require that operators consider certain risk factors in deciding when to install EFVs would be appropriate. They also found 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, that distribution pipelines are safe. Incidents continue to occur, but their frequency has been reduced. There is room for improvement. This Phase 1 effort concluded that implementing integrity management, consistent with the findings and conclusions of the work/study groups, should help achieve additional improvement.

Distribution is different than transmission. The inspection techniques required for hazardous liquids and gas transmission would not be technically feasible to perform on distribution pipelines. The basic principles: understanding the pipeline system, its threats and risks; and doing something to address those risks clearly apply. Additionally, further reducing accidents by requiring common actions everywhere would have been inefficient, ineffective, and overly burdensome. Thus, PHMSA needed to take a slightly different approach to apply the basic principles to distribution.

Pipeline Inspection, Enforcement, and Protection Act of 2006

Congress considered the DOT Inspector General recommendations and PHMSA's report to Congress, both discussed above, and the results of the Phase 1 work as part of reauthorizing DOT's pipeline safety program in 2006. The reauthorization act, the Pipeline Inspection, Enforcement, and Protection Act of 2006 (PIPES Act), became law on December 29, 2006. Section 9 of the PIPES Act required DOT to publish minimum standards (i.e., regulations) for integrity management programs for distribution pipelines. This section specifically noted that, as part of these standards, DOT could require operators of distribution pipelines to continually identify and assess risks on their distribution lines, to remediate conditions that present a potential threat to line integrity, and to monitor program effectiveness. The PIPES Act further required that each operator of a distribution pipeline that DOT determined was subject to the minimum standards it prescribed develop and implement an integrity management program in accordance with those standards. The Act explicitly reserved to States the authority to establish additional regulations, beyond those published by DOT, addressing distribution integrity management

Pursuant to this direction, PHMSA continued its efforts to develop a high-level federal regulation, consistent with the findings of the Phase 1 study.

The PIPES Act also addressed the issue of excavation damage. The Act[3] required persons who engage in demolition, excavation, tunneling, or construction activities to notify State One-Call systems before beginning such work in all States that had adopted such a program. DOT was authorized to take enforcement action against persons who violated this requirement in States that did not effectively enforce One-Call requirements themselves. The Act also authorized DOT to provide grants to States and municipalities to develop and improve their One-Call programs provided that the programs included, or were being developed to include, nine elements of an effective One-Call program. The nine elements specified in the Act, and thus required by law, were those enumerated in the Phase 1 work, as discussed above.

Developing Guidance Material

The Phase 1 work, as described above, had concluded that operators would need guidance to implement the envisioned high-level federal regulation. PHMSA and its State partners agreed, and

[3] PIPES Act, Section 2.

further recognized that operators, and the public, would need to have access to such guidance to comment meaningfully on a proposed high-level regulation. For example, a requirement to “know your infrastructure” might not elicit any comments, while a more detailed discussion of what an operator might be expected to do to demonstrate this knowledge might. PHMSA and NAPSR concluded that guidance needed to be developed in parallel with PHMSA’s drafting of the proposed rule, so that both would be available during the public comment period.

PHMSA and NAPSR jointly petitioned the Gas Piping Technology Committee (GPTC) to develop and publish guidance material. GPTC has been publishing guidance (The GUIDE) to help gas pipeline operators comply with federal pipeline safety requirements in 49 CFR Parts 191 and 192 since 1970. It began as a committee of the American Society of Mechanical Engineers (ASME). It has been accredited by the American National Standards Institute (ANSI) since 1992 (Committee Z380). GPTC is a large, well-balanced, committee operating by consensus under ANSI rules. As part of its regular activities, GPTC reviews new regulations published by PHMSA and then develops and publishes guidance operators can use to assure they comply with the new requirements.

That process had to be changed to develop guidance that would be available at the time a proposed rule was published. GPTC accepted the PHMSA/NAPSR petition and agreed to change its process to meet the regulators’ needs. GPTC established a task force for this purpose. GPTC invited additional members from industry and state regulators, who had participated in the Phase 1 work, to participate in task force activities. PHMSA participated in task force activities as an observer. Active participation by PHMSA was precluded by federal requirements that prohibit a regulatory agency from discussing proposed rules during their development unless all possible parties are involved (i.e., *ex parte* rules).

The *ex parte* requirements also meant that GPTC needed to develop guidance for distribution integrity management without first seeing what the federal requirements would be. Instead, GPTC focused on developing guidance that would implement the seven key elements described in the Phase 1 report. The integrity management guidance developed by the GPTC task force provided detailed examples to help distribution pipeline operators implement these elements. This included guidance on how to identify applicable threats. It also described options for analyzing risks, including a simple risk assessment method and more comprehensive, computer-based options. The guidance described possible actions not required by regulation that operators could take to manage important risks (called additional and accelerated – A&A – actions) and means of measuring the performance of integrity management programs.

GPTC published draft guidance that was available for review during the comment period for PHMSA’s proposed distribution integrity management rule. The Committee reviewed the final rule after it was published. The guidance was published in final form after changes were made to conform to the language in the final rule. GPTC published the distribution integrity management guidance as an appendix to the GUIDE, and made it available for purchase separately by operators who did not want to purchase the entire GUIDE (typically smaller distribution pipeline operators with simpler pipeline systems and more-limited resources). PHMSA is grateful to GPTC for its assistance and for the changes they made to their normal processes to accommodate the unusual needs of this endeavor.

GPTC's product was not the only guidance prepared to assist operators in implementing integrity management for distribution pipelines. Many distribution pipeline systems are operated by municipalities, often in conjunction with other utilities (e.g., water, sewer). Many of these distribution systems are small and their operators have limited technical staff. These operators are typically members of the American Public Gas Association (APGA). APGA concluded that more-specific guidance was needed to support these small operators without in-house engineering staffs.

PHMSA contracted with APGA's Security and Integrity Foundation (SIF) to produce jointly a guidance product for these small operators. The result – Simple, Handy, Risk-based Integrity Management Plan (SHRIMP) – is a computer-based process to aid small distribution operators. SHRIMP is based on the GPTC guide, but automates many of the decisions that an operator would make in implementing the guide based on the context of a small, simple pipeline system. Operators enter information describing their pipeline system and answer other questions in response to prompts generated by the program. The result is an integrity management plan including a basic analysis of the relative risks within a pipeline system and a suggestion of actions (i.e., A&A actions) that could be taken to manage those risks.

Rulemaking

PHMSA published its proposed rule for distribution pipeline integrity management on June 25, 2008. PHMSA agreed with the Phase 1 conclusion that the diversity among distribution pipeline systems made it impractical to establish prescriptive requirements. The proposed rule, as suggested by the Phase 1 conclusions, presented its requirements at a high-level, allowing a great degree of flexibility to distribution pipeline operators in how they designed their integrity management programs to satisfy those requirements. The proposal required that each operator prepare and implement a written integrity management program containing the seven key elements identified in the Phase 1 work and described above. PHMSA also agreed with the Phase 1 conclusion that distribution integrity management requirements should apply to entire pipeline systems, and the proposed rule did not include a requirement to identify high consequence areas within the pipeline system.

The proposed rule included a number of elements not studied or suggested by the Phase I work:

- A requirement to install an excess flow valve (EFV) on each new or replaced service line. This requirement was in response to a legislative mandate and is discussed further below.
- Allowance for operators to apply to their regulatory agencies to use alternate intervals for actions that Part 192 requires to be taken on a defined periodic basis (e.g., leak surveys). The alternate intervals must be based upon the operator's risk assessment of its pipeline. This

option was intended to improve efficiency in assuring safety by allowing operators to reduce the frequency of such actions in areas where their risk assessments demonstrated such reductions would not adversely affect safety, making resources available to apply to areas/threats of more importance to safety.

- Requirements for a simpler, streamlined integrity management program for master meter operators and operators of liquefied petroleum gas (LPG) systems. These are, by definition, distribution pipeline systems. They are typically smaller than municipal distribution systems and are simpler (i.e., contain a limited set of component parts).
- Requirements to report all failures of plastic pipe to PHMSA. Plastic pipe represents more than 50 percent of distribution pipelines and operational history has shown that there have been safety concerns with some plastic pipe (e.g., certain lots subject to cracking). The industry had responded to these problems by establishing the Plastic Pipeline Data Committee (PPDC) to collect and analyze data on plastic pipe failures. PHMSA was concerned that participation in PPDC was voluntary and that the knowledge gained from that program might not be reaching all the distribution pipeline operators who needed it.
- A requirement that each distribution integrity management program include a "performance through people" component specifically seeking to reduce the occurrence of accidents from acts of commission or omission by pipeline operator staff and to reduce the consequences of incidents that do occur by enhancing the incident response of that same staff.

The initial comment period of 90 days was extended, and comments were due by October 23, 2008. PHMSA received 143 letters commenting on the proposed rule. The vast majority of commenters supported the proposed rule, although some objected to specific provisions. Most of the negative comments related to proposed provisions that went beyond those suggested in the Phase 1 work.

As a result of its review of the public comments, PHMSA made a number of changes in the final rule:

- The mandatory reporting of plastic pipe failures was deleted. Comments from industry, and PPDC itself, convinced PHMSA that the results of PPDC analyses are widely available, even though all distribution operators do not voluntarily participate in PPDC. In particular, APGA reported that it disseminated PPDC reports to its members, helping to assure that information reached small distribution pipeline operators. As a result, PHMSA concluded that the proposed reporting to PHMSA was unnecessary.
- The proposed requirements for a "performance through people" component in all distribution integrity management programs were deleted. Commenters noted that the effects of operator personnel on pipeline safety were addressed by several existing regulations and questioned what additional actions could be taken as part of integrity management programs. PHMSA agreed that the cited regulations adequately addressed potential impacts on safety by operator personnel.
- The proposed requirements allowing operators to modify the required intervals for actions already required by regulations were modified to require that the proposed change result in an overall improvement in safety. This was intended to avoid parsing of actions and disapproval of proposed interval reductions that may result in a small increase in risk even

though the redirection of safety resources that the change would allow would result in a larger improvement in safety.

- The simplified requirements applicable to master meter and LPG operators were revised to limit their applicability to master meters and small LPG system operators. Comments noted that some LPG distribution systems are large, serve entire municipalities, and are essentially indistinguishable from natural gas distribution system operators. In addition, LPG is heavier than air and will not dissipate into the atmosphere as readily in the event of a leak. Commenters argued that these factors made it important that LPG systems be subject to IM requirements. PHMSA agreed, but noted that small LPG systems could be overwhelmed by the more-extensive requirements. Instead, PHMSA adopted a threshold already used in the regulations (to limit requirements to submit annual reports) and made the simplified requirements applicable only to LPG operators serving fewer than 100 customers from a single source. PHMSA also revised the simplified requirements to require master meter and small LPG operators to rank risks.
- Requirements for retention of documents were modified.
- Definitions were included for new terms "excavation damage" and "hazardous leaks." In addition, the existing definition of replaced service line in section 192.383 was retained, helping to clarify where EFVs must be installed.
- The requirement to install an EFV in new and replaced service lines was relocated from Subpart P to Subpart H, replacing the existing section 192.383. Requirements for EFVs are discussed further below.

For a complete discussion of the comments PHMSA received in response to the proposed rule and the changes made in the final rule, see the Federal Register notice by which the final rule was published. The final rule was published in the Federal Register on December 4, 2009. Distribution operators must develop and implement their integrity management plans by August 2, 2011.

Excess Flow Valves (EFV)

As noted above, the final rule includes a requirement that distribution pipeline operators install an EFV on all new and replaced service lines serving single-family residences. This is not, per se, an integrity management requirement. As described above, the Phase 1 work/study groups considered the use of EFVs and concluded that there should be no federal requirement but, rather, that they should be considered one mitigation option among many for consideration by operators. A description of why this requirement was included in the final rule is thus appropriate.

EFVs are safety devices that provide protection against consequences resulting from severance of the service line in which they are installed, such as excavation damage that results in a complete break of the line. The valves are relatively inexpensive to install when a service line is being installed or replaced. Installation costs rise considerably if EFVs are retrofitted, since the service line (and possibly its connection to the main) must be excavated to install the valve. The valves activate when gas flow exceeds the maximum expected in the service line, completely shutting off gas flow. An EFV thus provides protection against complete severance of the service line but may not provide protection for holes or breaks in the line that do not provide a flow similar to complete severance.

Whether EFVs should be required has been a subject of debate for many years. Those in favor of requiring their use argued that the costs were minimal and that the valves could save lives and property damages. Those opposed noted that an individual EFV provided protection for only one service line, which average about 65 feet in length; many EFVs must be installed before there is statistical assurance of any benefit in terms of lives saved or property damage avoided. Several cost-benefit studies have been performed. All concluded that the costs and benefits were near equal; whether costs exceeded benefits, or vice versa, often depended on the assumptions made in a specific analysis. All analyses agreed, however, that the increased costs associated with retrofit made requiring EFVs on a retrofit basis uneconomical, unless the service line was being excavated for other reasons.

PHMSA initially took a middle course. It published a rule in 1998 (49 CFR 192.383) that required operators to inform customers ordering new or replaced service lines of the availability of an EFV and its costs and benefits. The regulation required the operator to install an EFV if the customer requested it and agreed to pay the associated costs. Use of EFVs increased following publication of this rule, but their use was still far from universal. The debate continued up to and through the consideration of integrity management requirements for distribution pipelines, prompting the consideration by the Phase 1 work/study groups described above.

Congress included a requirement in the PIPES Act that PHMSA publish a regulation requiring installation of an EFV if:

> "(i) the service line is installed or entirely replaced after June 1, 2008;
> (ii) the service line operates continuously throughout the year at a pressure not less than 10 pounds per square inch gauge;
> (iii) the service line is not connected to a gas stream with respect to which the operator has had prior experience with contaminants the presence of which could interfere with the operation of an excess flow valve;
> (iv) the installation of an excess flow valve on the service line is not likely to cause loss of service to the residence or interfere with necessary operation or maintenance activities, such as purging liquids from the service line; and
> (v) an excess flow valve meeting performance standards developed under section 60110(e) of title 49, United States Code, is commercially available."

The final distribution integrity management rule includes a requirement that operators install EFVs on new and replaced service lines pursuant to this legislative direction. That requirement replaces the prior notification requirement in §192.383, which has been repealed.

Appendix A – Summary of DIMP Related Federal Register Notices

The following is a listing with summary of federal register notices related to the Distribution Integrity Management rule.

1) 73 FR 36015- June 25, 2008 - Integrity Management Program for Gas Distribution Pipelines; Notice of Proposed Rulemaking

   Title: Integrity Management Program for Gas Distribution Pipelines

   SUMMARY: PHMSA proposes to amend the Federal Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement integrity management (IM) programs. The purpose of these programs is to enhance safety by identifying and reducing pipeline integrity risks. The IM programs required by the proposed rule would be similar to those currently required for gas transmission pipelines, but tailored to reflect the differences in and among distribution systems. In accordance with Federal law, the proposed rule would require operators to install excess flow valves on certain new and replaced residential service lines, subject to feasibility criteria outlined in the rule. Based on the required risk assessments and enhanced controls, the proposed rule also would establish procedures and standards permitting risk-based adjustment of prescribed intervals for leak detection surveys and other fixed-interval requirements in the agency's existing regulations for gas distribution pipelines. To further minimize regulatory burdens, the proposed rule would establish simpler requirements for master meter and liquefied petroleum gas (LPG) operators, reflecting the relatively lower risk of these small pipeline systems.

   This proposal also addresses statutory mandates and recommendations from the DOT's Office of the Inspector General (OIG) and stakeholder groups.

2) 73 FR 52938 - Sep 12, 2008 - Extension of Comment Period DIMP NPRM

   Title: Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines; Proposed rule; extension of comment period.

   SUMMARY: PHMSA is extending the period for public comment to give interested persons an additional 30 days to comment on a proposed rule to amend the Federal Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement integrity management (IM) programs.

3) 74 FR 63906- 74 FR 63906 - December 4, 2009 - Integrity Management Program for Gas Distribution Pipelines; Final Rule

   Title: Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines. Effective Date: This Final Rule is effective - February 2, 2010.

SUMMARY: This final rule is amends the Federal Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement integrity management (IM) programs. The IM programs required by this rule are similar to those required for gas transmission pipelines, but tailored to reflect the differences in and among distribution pipelines. Based on the required risk assessments and enhanced controls, the rule allows for risk-based adjustment of prescribed intervals for leak detection surveys and other fixed-interval requirements in the agency's existing regulations for gas distribution pipelines. To minimize regulatory burdens, the rule establishes simpler requirements for master meter and small liquefied petroleum gas (LPG) operators, reflecting the relatively lower risk of these small pipelines. In accordance with Federal law, the rule also requires operators to install excess flow valves on new and replaced residential service lines, subject to feasibility criteria outlined in the rule. This final rule addresses statutory mandates and recommendations from the DOT's Office of the Inspector General (OIG) and stakeholder groups.

4) 74 FR 69286 – December 31, 2009 - Extension of comment period for compression coupling failure reporting and annual report information collection, OMB Control Number 2137–0522

Title: Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines

SUMMARY: PHMSA is extending for 30 days, until February 4, 2010, the period for filing comments to the requirement adopted in the final rule, ''Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines'' to require the reporting of failures of compression couplings used in metal pipe. PHMSA had invited public comment on the extension of this requirement to include reporting of failure of compression couplings used in metal pipe until January 4, 2010. The American Gas Association (AGA) requested that PHMSA extend the comment period for thirty days.

5) 75 FR 5244 – February 2, 2010 - Correction for the Integrity Management Program for Gas Distribution Pipelines

Title: Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines; Correction

SUMMARY: PHMSA is correcting a final rule that appeared in the Federal Register on December 4, 2009. That final rule amended the Federal Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement integrity management programs. In addition to a minor correction in terminology, this document corrects an erroneous effective date given in the December 4 publication.

6) 75 FR 36615 - Jun 28, 2010 - Request for public comments and OMB approval of modifications to an existing information collection.

Title: Pipeline Safety: Information Collection Gas Distribution Annual Report Form

Summary: As required by the Paperwork Reduction Act of 1995 (PRA), the Pipeline and Hazardous Materials Safety Administration (PHMSA) published a notice in the Federal Register on

December 4, 2009, under Docket No. PHMSA-2004-19854 of its intent to revise the agency's Gas Distribution System Annual Report Form (PHMSA F 7100.1-1). PHMSA F 7100.1-1 is covered under the PHMSA information collection titled: "Incident and Annual Reports for Gas Pipeline Operators," with an OMB Control Number of 2137-0522. PHMSA is publishing this notice to respond to comments and announce that the revised information collection will be submitted to OMB for approval. This notice also informs operators of gas distribution systems that PHMSA is planning for the revised Annual Report Form, once approved, to be used for the 2010 calendar year and submitted to PHMSA by March 15, 2011. The portion of the annual report relative to mechanical fitting (compression couplings) failures will be delayed by one year and will take effect starting with the 2011 calendar year.

7) 76 FR 5494 – Feb. 1, 2011 - Mechanical Fitting Failure Reporting Requirements

Title: Pipeline Safety: Mechanical Fitting Failure Reporting Requirements

SUMMARY: This final rule is an amendment to PHMSA's regulations involving DIMP. This final rule revises the pipeline safety regulations to clarify the types of pipeline fittings involved in the compression coupling failure information collection; changes the term ''compression coupling'' to ''mechanical fitting,'' aligns a threat category with the annual report; and clarifies the Excess Flow Valve (EFV) metric to be reported by operators of gas systems. This rule also announces the OMB approval of the revised Distribution Annual Report and a new Mechanical Fitting Failure Report. Finally, this rulemaking clarifies the key dates for the collection and submission of the new Mechanical Fitting Failure Report.